2005
Long-Term
Reliability Assessment

The Reliability of
Bulk Electric Systems
in North America

North American Electric Reliability Council
September 2005

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INTRODUCTION

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

- An assessment of long-term electric supply and demand and transmission reliability through 2014;
- 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.

This assessment projects trends in electric supply and demand and transmission conditions over the next several years. The trends are based on the most accurate and up-to-date information available at the time the assessment was prepared and should not be considered an absolute prediction of system conditions.

In preparing this report, RAS:

- Reviewed summaries of regional self-assessments, including forecasts of peak electric 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.

Figure 1 (on page 7) contains a map of the NERC regional reliability councils.

EXECUTIVE SUMMARY

Resource Adequacy Dependent on New Generation Projects

Resources in the near term (2005–2009) will be adequate to meet customer demand throughout North America, provided new generating facilities are constructed as anticipated. In spite of this favorable outlook, a chance remains that an excessive number of equipment problems, coupled with high demands caused by extreme weather, could create localized supply problems. Generation additions and resulting capacity margins are not evenly distributed across North America, as shown in the *Adequacy Assessment* section of this report.

Peak demand is expected to grow by about 69,536 MW over the next five years, while projected resource additions over this same period total only about 48,719 MW, depending upon the number of merchant plants assumed to be in service. However, due to the short lead-time in generation development, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

Resource adequacy in the long term (2010–2014) is more uncertain. The following are among the factors that will influence long-term adequacy: 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; price and supply of fuel; and political and regulatory actions.

In areas of North America with a restructured electric industry, the addition of new generating capacity depends on several factors: 1) basic economic demand and supply fundamentals, 2) traditional planning reserve margin requirements and other resource adequacy criteria established by industry, utility, and regulatory groups, and 3) the response of power plant developers to relevant market signals. In these areas, capacity margins will likely fluctuate, similar to normal business cycles experienced in other industries. In areas that have not undergone restructuring, new capacity will be constructed primarily in response to resource adequacy criteria established by individual utilities or their regulators.

Transmission Systems Will be Operated at or Near Limits More Frequently

North American transmission systems are expected to meet reliability requirements in the near term. However, as customer demand increases and transmission systems experience increased power transfers, portions of these systems will be operated at or near their reliability limits more of the time. Under these conditions, coincident failures of generating units, transmission lines, or transformers, while improbable, can degrade bulk electric system reliability.

The following elements are critical to maintaining system reliability under these conditions:

- Compliance with NERC and regional reliability standards;
- Knowledge by users and operators of the bulk electric system of their responsibilities and actions required to maintain reliability under all system conditions;
- System operators trained to recognize emergency system conditions and having the authority and responsibility to take actions necessary to preserve reliability;
- Availability and effective use by system operators of monitoring and analysis tools;
- Wide-area control and communications systems;
- Adequate reactive supply margins, including the balance between static and dynamic reactive resources; and
- Completion of needed transmission additions.

The *2004 Long-Term Reliability Assessment*[1] prepared last year contains a more detailed description of these issues.

Even though NERC expects the transmission systems to operate reliably, some portions of the grid will not be able to support all desired electricity market transactions. Some well-known transmission constraints are recurring, while new constraints appear as electricity flow patterns change. See individual regional self-assessments for details, which begin on page 29.

In cases where generation redispatch options have been exhausted or are ineffective, the only way to relieve these constraints is to build new generation downstream of the constraint, implement demand-reduction measures, or increase the capacity of the transmission system. 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.

More than 7,122 miles of new transmission (230 kV and above) are proposed to be added through 2009, with a total of about 12,484 miles added over the 2005–2014 time frame. The increase represents a 5.9% increase in the total miles of installed extra high voltage (EHV) transmission lines (230 kV and above) in North America over the 2005–2014 assessment period. New transmission line construction is not the only means of ensuring transmission adequacy, as discussed in the *Transmission Issues* section of NERC's *2004 Long-Term Reliability Assessment* report. For example, upgrading or replacing existing lower capacity transmission lines increases the capacity and reliability of the existing transmission network, but does not increase the reported miles of transmission lines.

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. A combination of market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also will influence the siting and construction of new transmission facilities.

Fuel Supply Adequate in Most Regions

Most regions do not anticipate any long-term problems with fuel supplies for the assessment period. However, short-term interruptions of supply could occur during the period, and affected generators will need to implement contingency plans to manage the operation of their facilities. For example, at the time this report was written, deliveries of western coal from the Powder River Basin were being curtailed due to rail track maintenance. The response to this curtailment of coal deliveries will vary by region and degree of reliance on coal generation. NERC's initial review did not find any region in which this situation would pose a serious adverse impact on a region's ability to reliably serve customer demand. NERC will issue a supplemental report if conditions warrant; RAS will also continue the investigation during its 2005/2006 winter assessment.

Hydroelectric resources will be affected 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 *Gas Electricity Interdependency Issues* section of this report.

[1] http://www.nerc.com/~filez/rasreports.html

Figure 1: NERC Regional Reliability Councils

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network, Inc.

MRO
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Regional Areas of Interest

ECAR — After many years of regulatory delays, the American Electric Power (AEP) Wyoming to Jacksons Ferry 765-kV transmission line is now under construction. This line was originally proposed for service in May 1998. Construction progress is on schedule and completion of the project is now expected in June 2006. Once completed, this project will mitigate significant reliability risks that have been addressed on a temporary basis by the use of complex operating procedures.

ERCOT — Mothballing and retirement of generation capacity has resulted in significantly lower capacity margins than found in previous assessments, particularly for the near term. Capacity margins, however, are expected to be near, but above, the minimum requirement of 11% until 2010. Given ERCOT's primary dependence on natural gas-fueled generation, the future adequacy of natural gas supply during extended periods of cold weather remains a concern.

FRCC — Gas-fired generation continues to dominate a high percentage of new generation. Electricity produced from natural gas-fired generators is forecast to increase from 30% in 2004 to 45% in 2014. FRCC adopted a high-level methodology to assess its natural gas pipeline and electric interdependency and concluded that it will have adequate natural gas pipeline capacity into the region for the next five years.

MAAC — Based on identified system enhancements, projected demand growth, and generation, MAAC has concluded transmission capability over the next five years is expected to meet MAAC transmission planning criteria. Transmission upgrades in the northern New Jersey area for the years 2008–2010 are still under evaluation to accommodate generator retirements and maintain transmission system reliability within the applicable criteria.

For the period of 2009 to 2014, MAAC expects additional generation to be constructed to meet reliability needs because additional incentives are under consideration for generation developers to locate generation in areas where capacity is required. Transmission expansion is another way to get capacity to the needed areas to meet the MAAC reliability requirements but transmission expansion would take more time and effort to install.

MAIN — In last year's long-term assessment, MAIN projected about 9,900 MW of additional capacity resources in the region by 2014. Of that amount, about 5,700 MW or 58%, were from combustion turbines and combined-cycle plants. In this year's long-term assessment, MAIN projects about 5,600 MW of additional capacity resources within the region by 2014. Of that amount, about 950 MW or 17% are combustion turbines and combined-cycle plants. The magnitude of the variation in additional capacity resources from last year to this year reflects the uncertainty the region faces in assessing long-term resource adequacy. The region is also concerned with the volatility associated with long-term resource planning.

MRO — System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO 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. This line is expected to be in service in 2008.

NPCC — The Ontario government has committed to the phasing out of coal-fired generation in the province when replacement resources become available. As part of this initiative, the 1,148-MW, coal-fired Lakeview thermal generating station ceased operation at the end of April 2005; about 6,400 MW of coal-fired capacity in addition to the Lakeview station remains in service. Since coal-fired generation accounts for about 21% of Ontario's current generating capacity, a substantial amount of new supply, refurbished generation, or additional demand-side resources will be required. By the summer of 2015, the region must address a deficiency of 4,239 MW. In the interim, it will be important to maintain the reliability of existing coal-fired generating stations despite their planned shutdown. Ontario's Independent Electricity System Operator (IESO) will continue working with the provincial government to ensure that an appropriate amount of replacement supply or demand initiatives, at suitable locations, is reliably available before the coal-fired generators are shut down.

To meet critical near-term electric system reliability needs in southwestern Connecticut for the next four years, ISO New England (ISO-NE) has secured emergency energy resources in that area. The resources provided about 218 MW during the summer of 2005 and will provide up to 255 MW by the summer of 2007 from emergency generation and demand-response resources, including reductions in electricity use and conservation resources.

Because of the high demand for natural gas for home and commercial heating needs, during the New England winter, the availability of natural gas to fuel the generation sector is an issue. In January 2004, New England experienced extremely cold temperatures coupled with high electrical demand. During this cold snap, more than 9,000 MW was out of service because natural gas was redirected back into the gas market, which caused ISO-NE to go into emergency operating procedures on January 14, 2004. As a result of this experience, ISO-NE and New England market participants developed Appendix H to Market Rule 1, Cold Weather Event Operations. The primary features of this new procedure are to:

- improve the availability of information about natural gas supply and transportation for use by ISO-NE operations personnel;
- improve the information provided to regional market participants regarding potential cold weather events and an assessment of power-system conditions during those events; and
- in extreme cases, shift the day-ahead energy market timeline to allow for early commitments of natural gas generators in anticipation of possible natural gas supply or transportation constraints and operable capacity shortages on the bulk power system.

SERC — Significant merchant generation development has occurred in SERC during the past few years. Much of this merchant generation has not been contracted to serve load within SERC or outside the SERC region and its deliverability is not assured. However, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets, indicating that a portion of the uncommitted resources is currently deliverable.

Large and variable loop flows are expected to affect transfer capabilities on a number of interfaces within SERC and between SERC and other regions. The proposed significant increases in merchant plant capacity over the next few years have led to increasing uncertainty in flow patterns on the transmission system.

SERC members invested more than $1 billion in new transmission lines and system upgrades in 2004, and they are planning transmission capital expenditures of more than $6 billion over the next five years.

SPP — In April 2005, FERC published its order ER05-109-000 conditionally approving the SPP Transmission Pricing Proposal, i.e., cost allocation and cost-recovery provisions. The new attachment Z of the SPP OATT provides the necessary mechanism for recovering costs for transmission upgrades identified in the tariff assessment processes. These tariff provisions should address long-standing concerns regarding uncertainty of cost recovery associated with transmission upgrades and facilitate the timely expansion of necessary transmission capacity within and around the SPP footprint.

WECC — Uncertainty in projections for generating capacity, energy production by generators, and the effects of customer energy efficiency and other demand-side management programs in California make long-term assessment of resource adequacy for this area difficult. Based on current projections, the California-Mexico subregion may need additional capacity of up to 10,700 MW to achieve the required 15% planning reserve margin for the 2010–2014 period. While a portion of that capacity may be available from other WECC subregions, most of it will have to come from new plants that are not presently identified.

Plans have been announced in WECC for 5,105 miles of 230-, 345-, and 500-kV transmission line construction and upgrades during the 2005–2014 assessment period to meet the growing demand. This transmission capacity is expected to be adequate to effectively supply firm customer demand and firm transmission requirements but may not be sufficient to eliminate all inter- and intra-region constraints.

Multiregional — ECAR, MAAC, and MAIN are working toward the formation of a larger regional reliability council, ReliabilityFirst Corporation (RFC), which will replace ECAR, MAAC, and portions of MAIN with a single council, RFC. RFC is tentatively scheduled to begin operations on January 1, 2006. The planning and operational policies and procedures of RFC supersede the policies and procedures of the existing three regions.

Definition of Reliability

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

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.

Under the heading of Adequacy, system operators can and should take “controlled” actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

* Public Appeals
* Voltage Reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%).
* Interruptible demand — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.
* Rotating blackouts — the term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, in effect rotating the outages among many sets of feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as “cascading blackouts” — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a “controlled blackout” or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

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, 2005 edition (http://www.nerc.com/~esd/).

Most new generation additions over the next few years will be constructed by the merchant generation industry. 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 EVA are used in this report to supplement data submitted by the NERC regions.

About NERC

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

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 (IPPs); 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

The blackout of August 14, 2003 clearly demonstrated that the existing scheme of voluntary compliance with NERC reliability rules is no longer adequate in a restructured industry. To ensure the continued reliability of the interconnected transmission grid, reliability rules must be made mandatory and enforceable and they must be applied fairly to all electric industry participants throughout North America. Changing from a strictly voluntary reliability system to an enforceable one requires federal legislation in the United States to establish an independent electric reliability organization. On August 8, 2005, NERC-supported reliability legislation took effect in the United States that establishes the foundation for making the reliability standards mandatory and enforceable.

NERC is working with the U.S. Federal Energy Regulatory Commission (FERC) and industry stakeholders to implement the bill's reliability provisions. NERC is also working with appropriate regulatory authorities in Canada to achieve an equivalent result.

ADEQUACY ASSESSMENT

Demand and Resource Projections

NERC expects electricity demand to grow by about 69,536 MW through the summer of 2009. Projected resource additions over this same period total about 48,719 MW, depending upon the number of merchant plants assumed to be in service. However, due to the short lead-time in generation development, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

The average annual peak demand growth over the 2005–2014 assessment period is projected to be 2.0% for the U.S. and 0.9% for Canada. The average annual peak demand growth rate for the last ten years has been 2.4% for the U.S. (summer), and 1.0% for Canada (winter). Please note that the demand growth-rate projections are a ten-year average and that individual years may experience higher or lower growth rates due to variations in economic conditions and weather.

In *Figures 2* and *3* (on the next page), the demand projections represent an aggregate of weather-normalized regional member projection assembled by the NERC Data Coordination Working Group. NERC's Load Forecasting Working Group (LFWG) then 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 dealing with diversity, weather, and economic conditions, which are key drivers of the demand forecast.

Forecast Bandwidths

Forecasts are based on probabilities and cannot precisely predict the future. Instead, forecasts typically encompass a range of possible outcomes to address future uncertainty. Each demand projection, for example, represents the most likely future outcome. Capacity resources historically have been planned to meet the most likely demand with an additional reserve to meet unusual conditions.

For planning purposes, not only is an estimate of the most likely future outcome useful, but so are those of potential variations. Accordingly, NERC's LFWG develops upper and lower confidence bands around demand projections. The confidence bands represent an 80% probability that future demand will occur between the upper and lower bands. Consequently, the chance that demand will be below the lower band is 10% and the chance demand will be above the upper band is 10%. Demand projections and their associated bandwidths are updated each year to reflect the latest conditions.

With the *2005 Long-Term Reliability Assessment*, the RAS will be including regional bandwidths to more clearly show the variability of demand within the respective regions.

Figures 2 and *3* also show overlays of projected capacity resources on the projected demand bandwidths. The NERC 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.

Accurately predicting the exact number and in-service dates of future capacity additions that merchant developers will actually construct is difficult. To supplement these traditional data sources in order to better understand the potential impacts of new generators, RAS has enlisted the services of EVA to provide detailed project information.[2] Using this information, announced new merchant plants were screened to establish those most likely to be built.

Figure 2 shows three resource curves: the first is based on NERC regional projections; the second adds uncommitted capacity to regional projections; and the third is the subcommittee's best estimate of future capacity resources (existing plus EVA).

Figure 2: U.S. Summer Capacity Versus Demand Growth

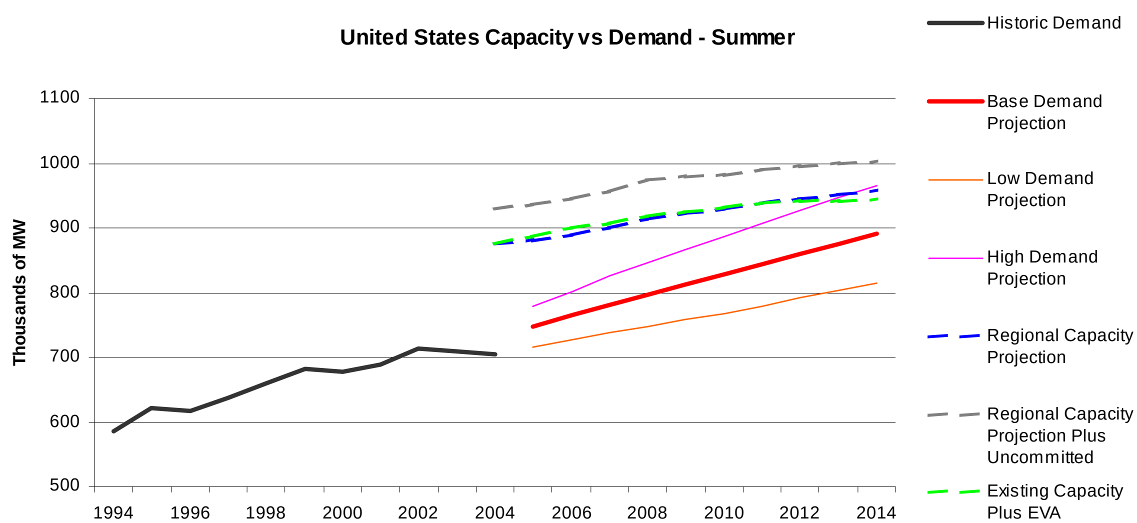
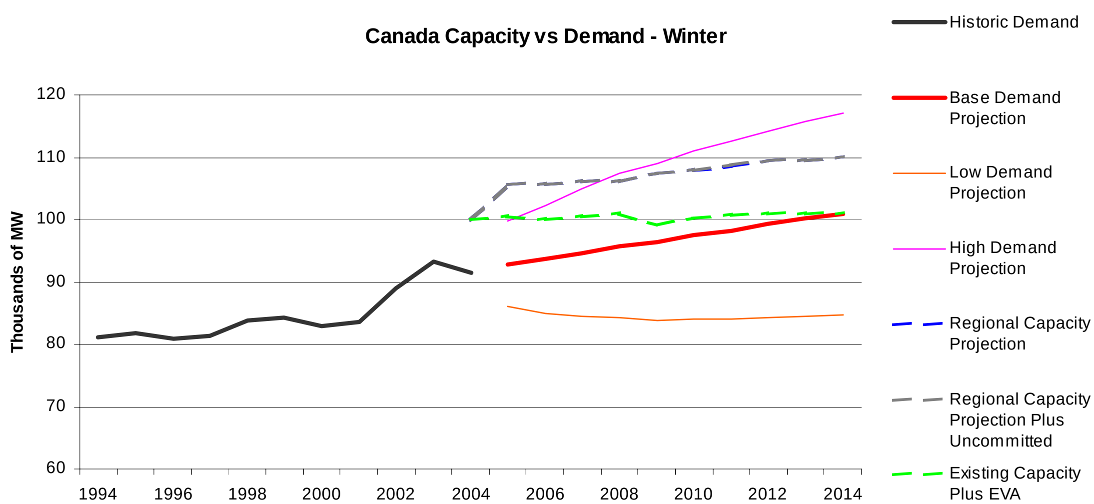


Figure 3 shows Canada's projected capacity resources for the assessment period, including all proposed new capacity resources reported by the NERC regions (note: uncommitted resources are very small, so the two regional data lines overlap on the graph below).

Figure 3: Canadian Winter Capacity Versus Demand Growth

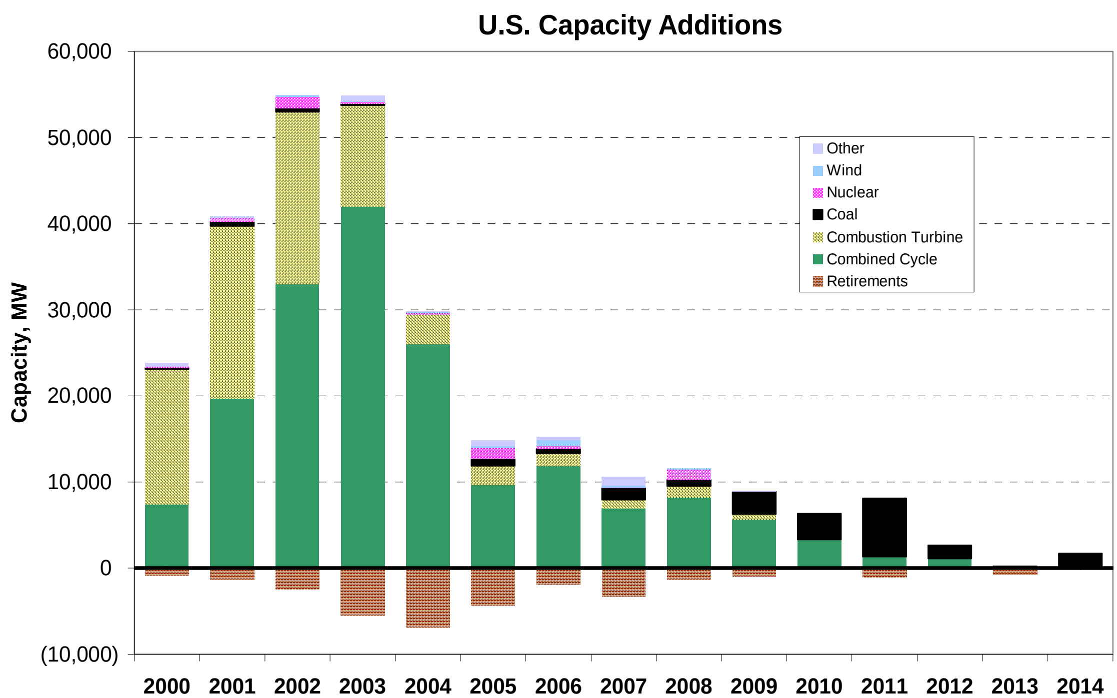


[2] EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output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

Capacity Additions

As *Figures 4* and *5* show, the overall projected amount of new generation is decreasing. In some areas generation has been overbuilt and a decrease in new construction is an expected response to the over-supply situation. In other areas, increases in generation additions that have not yet been identified may be continuing but because of the short lead time for construction of some generating facilities, those projects may not be included in announced plans.

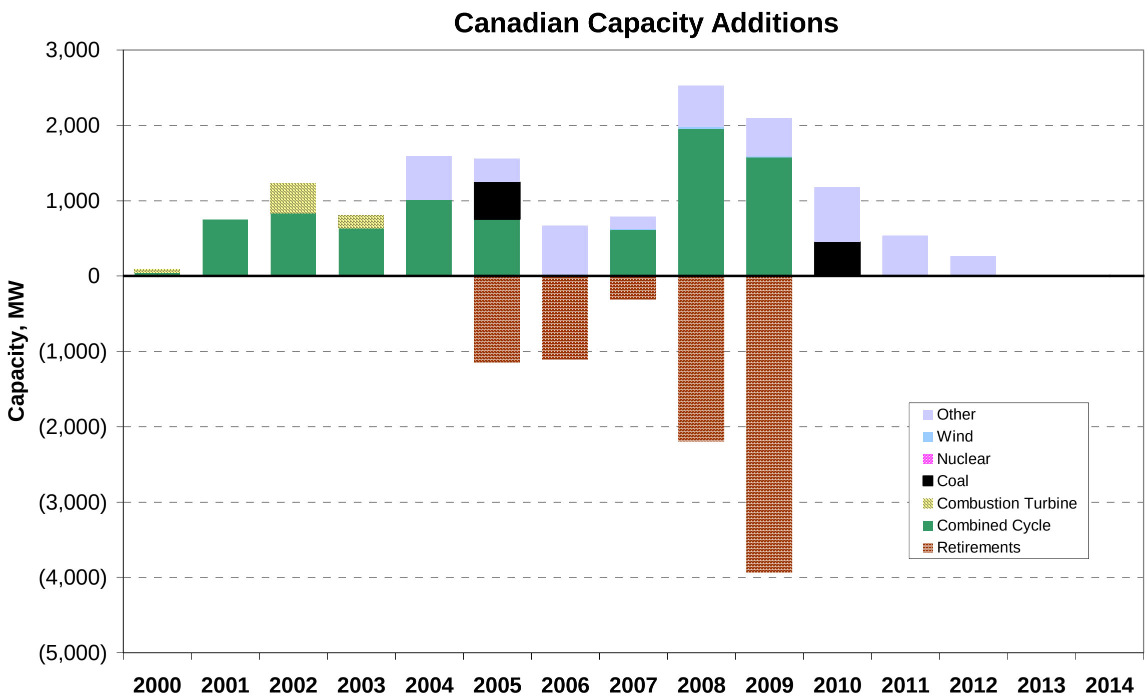
Figure 4: U.S. Power Plant Additions, Capacity Expansions, and Retirements by In-Service Year and Type



Notes:
1. Capacity additions for each year prior to summer peak load season.
2. Wind capacity not counted in reserve margin estimates.
3. Capacity additions for 2005 and 2006 are estimated.

Source: EVA — July 2005

Figure 5: Canada Power Plant Additions, Capacity Expansions, and Retirements by In-Service Year and Type

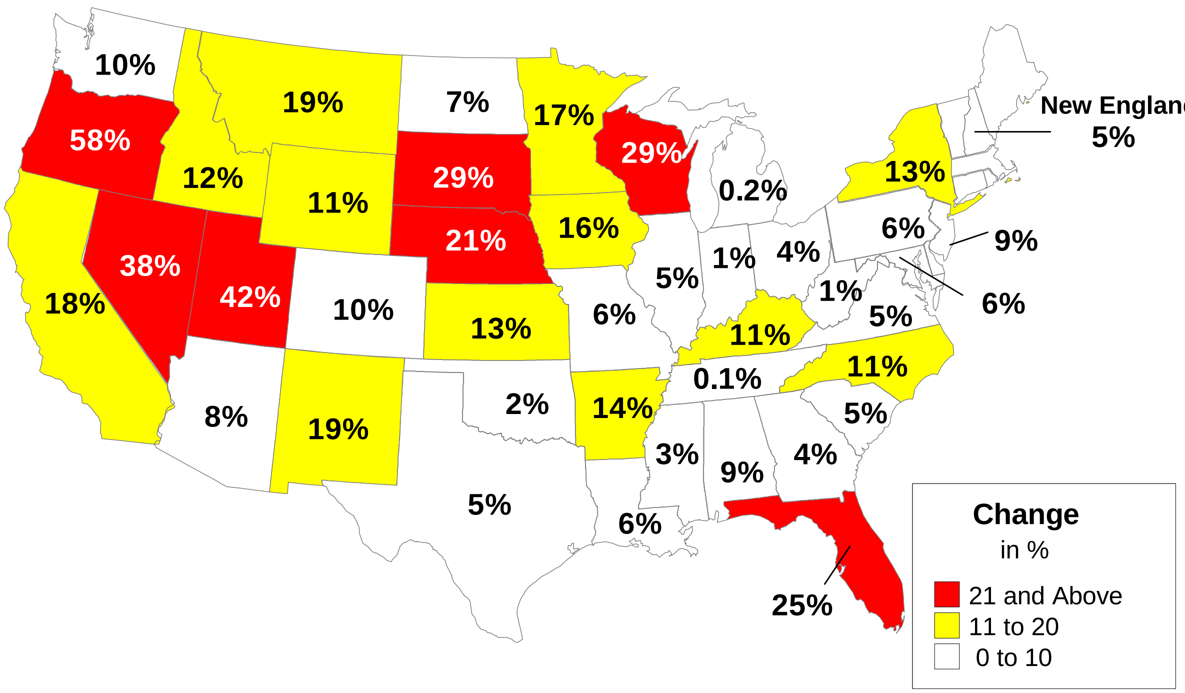


Notes:
1. Capacity additions for each year prior to summer peak load season.
2. Wind capacity not counted in reserve margin estimates.
3. Capacity additions for 2005 and 2006 are estimated.

Source: EVA — July 2005

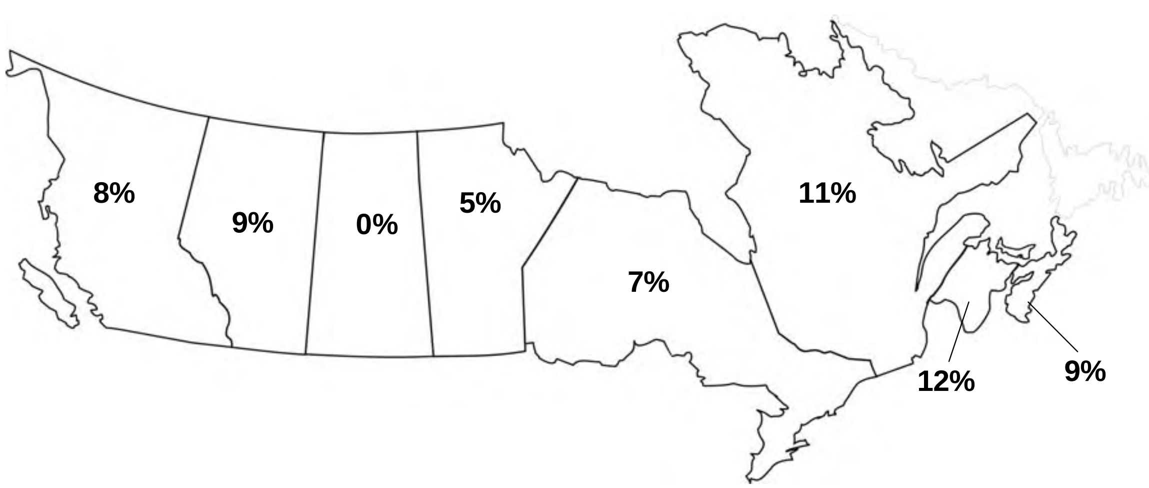
As *Figures 6* and *7* show, the locations being selected for the installation of new generators vary significantly from one state or province to another.

Figure 6: Amount of Projected New Generator Additions, 2005–2014, as a Percentage of 2004 Capacity: United States



Source: EVA — July 2005

Figure 7: Amount of Projected New Generator Additions, 2005–2014, as a Percentage of 2004 Capacity: Canada



Source: EVA — July 2005

Table 1 illustrates the effects of recent delays and cancellations of power plant projects in the amount of new power projects under development in the U.S. as compared to the 1998–2004 period. Canadian development activity has increased. (All projects under development do not necessarily reach commercial operation.)

Table 1: New Power Projects Under Development

Capacity Type	Capacity Additions (MW)			
	1998–2004 Total	**2005–2011 Subtotal**	**2012–2014 Subtotal**	**2005–2014 Total**
United States				
Combined Cycle	132,439	47,012	1,100	48,112
Simple Cycle	73,525	6,543	0	6,543
Coal	1,380	15,845	3,505	19,350
Nuclear	2,337	2,912	0	2,912
Wind	4,946	11,958	0	11,958
Other	1,542	2,216	0	2,216
Total U.S.	**216,168**	**86,486**	**4,605**	**91,091**
Canada				
Combined Cycle	3,321	4,901	0	4,901
Simple Cycle	744	0	0	0
Coal	0	940	0	940
Nuclear	0	0	0	0
Wind	0	742	0	742
Other	578	3,443	266	3,709
Total Canada	**4,643**	**10,026**	**266**	**10,292**

Source: EVA

Capacity Margins

Two different capacity margin projections are shown in *Figure 8*. The line labeled “Reported by Regions” reflects the capacity margins as reported by NERC regions. The line labeled “EVA Supplement” reflects the projected capacity margins after adjusting regional data with data received from EVA. The regional reporting often includes plans for generation additions based on capacity adequacy requirements, without firm construction plans. All of the capacity margin projections include the effects of currently planned generating unit retirements.

Figure 8: U.S. Summer Capacity Margins in Percent

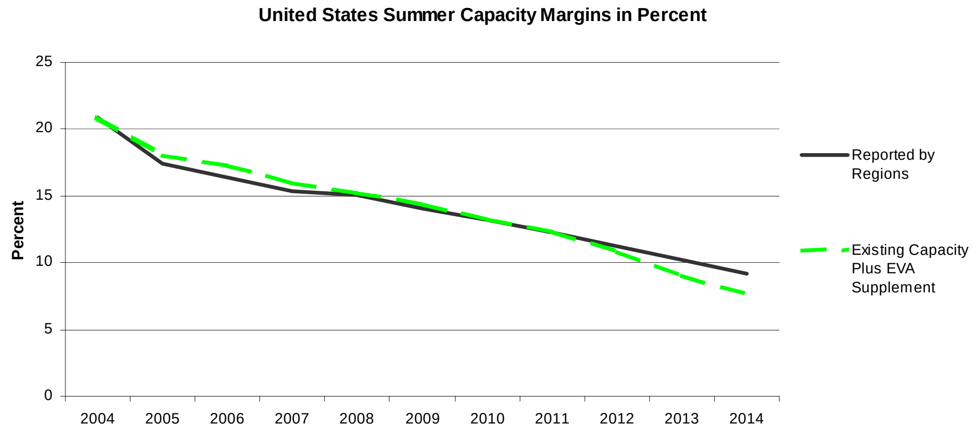


Figure 9 compares a series of four ten-year capacity margin projections for the U.S. as reported to NERC by the regions. Projected 2006 U.S. summer capacity margins are about 14.1% lower this year than last year's projection for 2006. The projected margin continues to decline during the latter half of the ten-year period to about 9.1%.

Figure 9: U.S. Summer Capacity Margin Projections

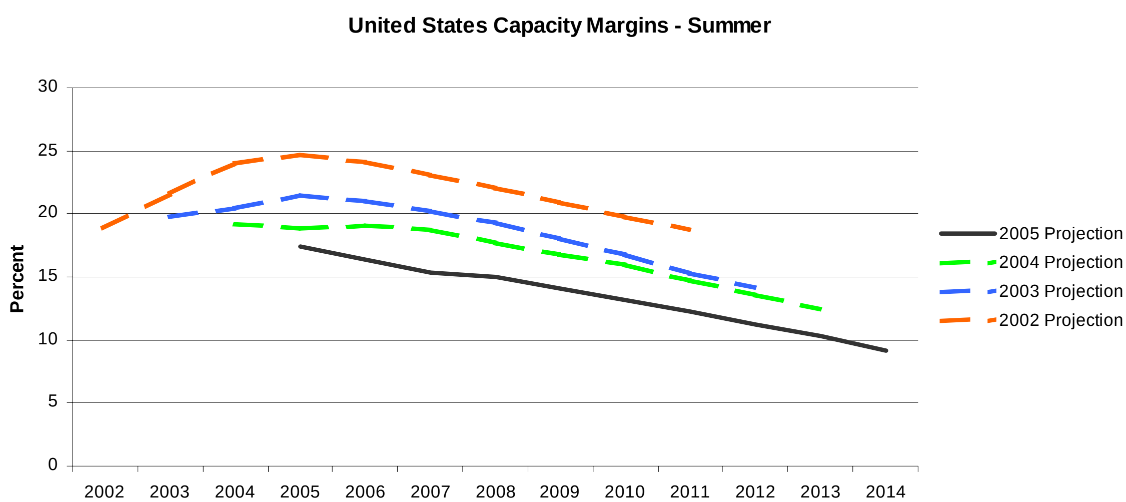
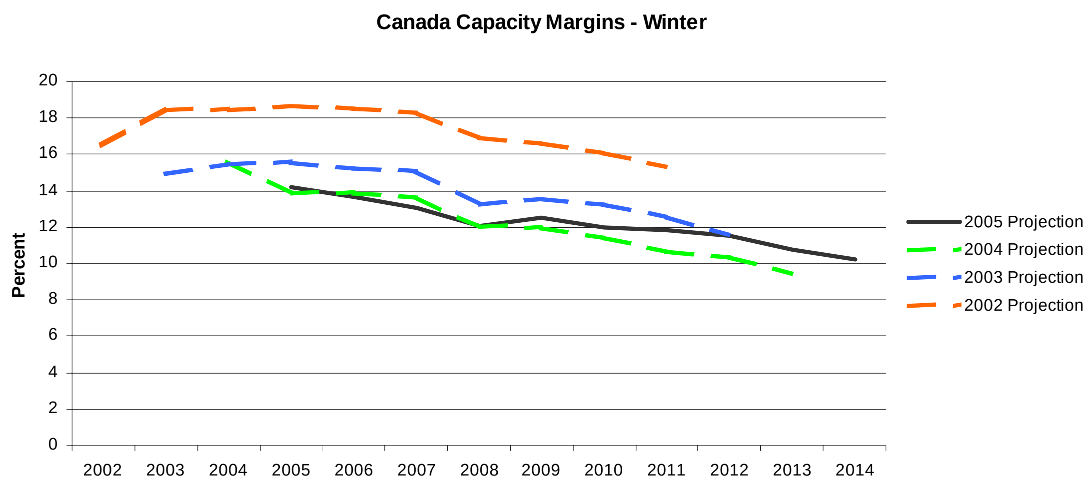


Figure 10 compares a series of four ten-year capacity margin projections for Canada as reported to NERC by the regions. Projected 2006/07 Canadian winter capacity margins are about 1.4% lower this year than last year's projection for 2006/07. The projected margin continues to decline during the latter half of the ten-year period to about 10.3%.

Figure 10: Canada Winter Capacity Margin Projection



Figures 9 and *10* are based strictly upon regional data submittals.

Energy Projections

Figures 11 and *12* show ten-year projections of net energy for load for the United States and Canada.

Figure 11: Net Energy for Load, 2005–2014: United States

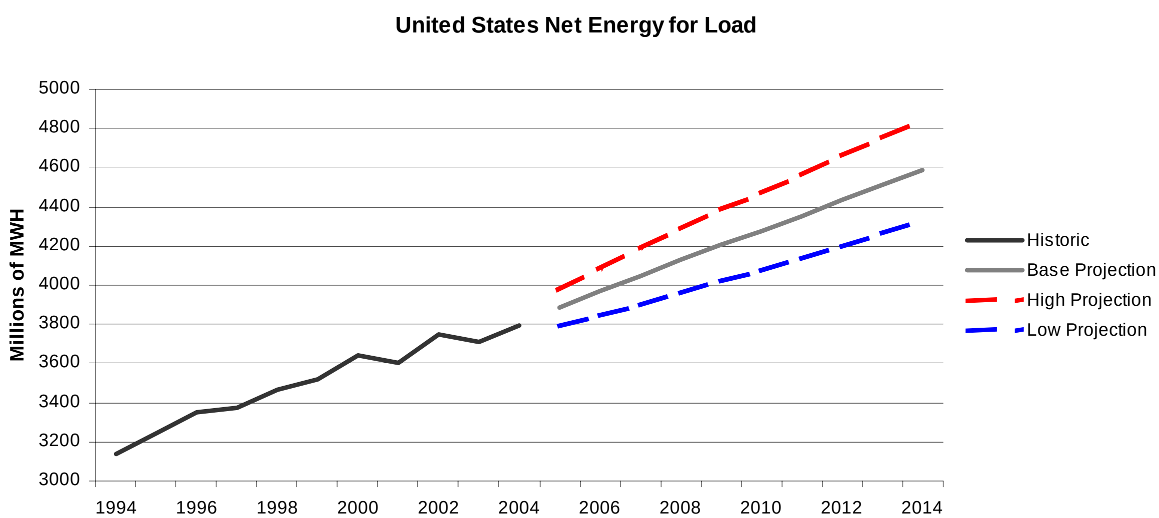
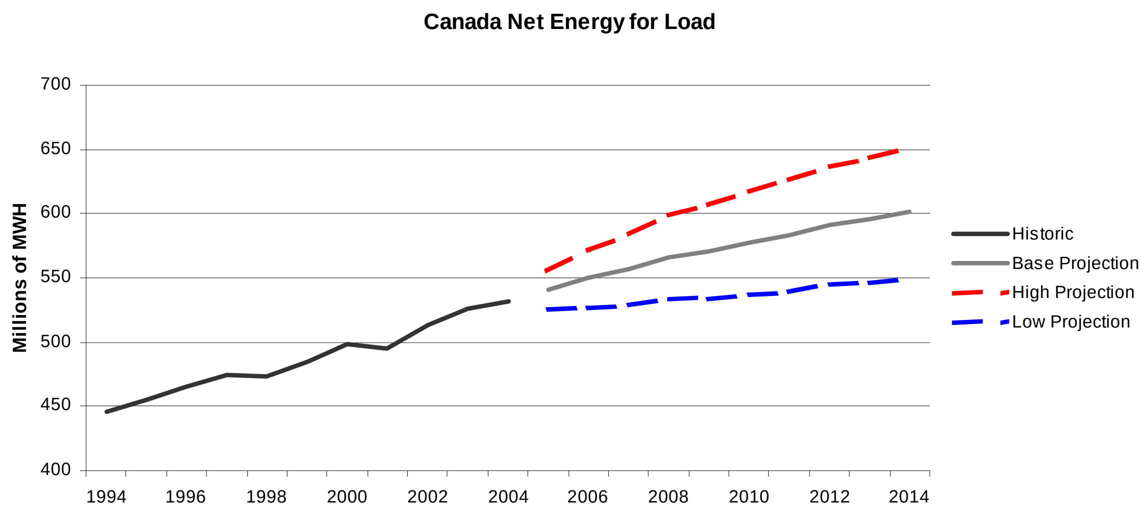


Figure 12: Net Energy for Load. 2005–2014: Canada



Regional Capacity and Demand Projections

The figures in the regional self-assessment pages show the regional historical demand, projected demand growth, capacity margin projections, and generation expansion projections reported by the NERC regions. These data are augmented by generation expansion data from EVA. Also included are pie charts comparing the projected change in the composition of capacity resources by fuel type from 2000 to 2010.

Capacity Fuel Mix

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

Note: the category "Other" may include capacity for which a fuel type has yet to be determined.

Figure 13: Sample — Relative Capacity by Fuel Mix

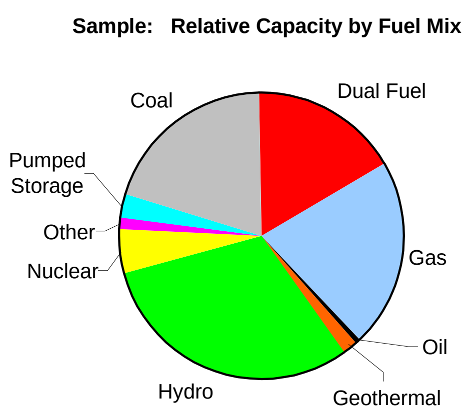


Table 2: Demand and Capacity as Reported by the NERC Regions

Region	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Planned Capacity Resources Reserve Margin (%)	Planned Capacity Resources Capacity Margin (%)	Uncommitted[3] Resources (MW)	Total[4] Potential Resources (MW)
Summer – 2006						
ECAR	104,230	128,326	23.1	18.8	780	129,106
FRCC	41,934	51,106	21.9	17.9	2,082	53,188
MAAC	57,981	69,855	20.5	17.0	0	69,855
MAIN	56,731	66,729	17.6	15.0	2,130	68,859
MRO-U.S.	30,442	35,965	18.1	15.4	0	35,965
MRO-Canada	5,641	7,727	37.0	27.0	0	7,727
NPCC-U.S.	58,078	69,917	20.4	16.9	0	69,917
NPCC-Canada	48,769	69,564	42.6	29.9	4	69,568
SERC	163,579	182,569	11.6	10.4	41,027	223,596
SPP	41,262	48,710	18.1	15.3	9,271	57,981
Eastern Interconnection	608,647	730,468	20.0	16.7	55,294	785,762
WECC-U.S.	128,692	166,946	29.7	22.9	0	166,946
WECC-Canada	16,733	21,690	29.6	22.9	0	21,690
WECC-Mexico	2,002	2,634	31.6	24.0	0	2,634
Western Interconnection[5]	147,411	191,270	29.8	22.9	0	191,270
ERCOT Interconnection	60,998	69,218	13.5	11.9	0	69,218
U.S.	743,927	889,341	19.5	16.4	55,290	944,631
Canada	71,143	98,981	39.1	28.1	4	98,985
Mexico	2,002	2,634	31.6	24.0	0	2,634
NERC	817,072	990,956	21.3	17.5	55,294	1,046,250
Summer – 2010						
ECAR	112,123	128,326	14.5	12.6	3,287	131,613
FRCC	46,803	55,914	19.5	16.3	2,082	57,996
MAAC	62,451	71,799	15.0	13.0	0	71,799
MAIN	61,162	70,238	14.8	12.9	3,437	73,675
MRO-U.S.	32,796	37,611	14.7	12.8	75	37,686
MRO-Canada	5,885	8,260	40.4	28.8	0	8,260
NPCC-U.S.	61,473	69,760	13.5	11.9	0	69,760
NPCC-Canada	50,697	69,524	37.1	27.1	0	69,524
SERC	178,844	193,909	8.4	7.8	32,993	226,902
SPP	44,270	50,859	14.9	13.0	9,271	60,130
Eastern Interconnection	656,504	756,200	15.2	13.2	51,145	807,345
WECC-U.S.	142,417	179,480	26.0	20.7	0	179,480
WECC-Canada	18,014	22,434	24.5	19.7	0	22,434
WECC-Mexico	2,482	3,065	23.5	19.0	0	3,065
Western Interconnection[4]	162,893	204,979	25.8	20.5	0	204,979
ERCOT Interconnection	65,051	72,399	11.3	10.1	0	72,399
U.S.	807,390	930,295	15.2	13.2	51,145	981,440
Canada	74,596	100,218	34.3	25.6	0	100,218
Mexico	2,482	3,065	23.5	19.0	0	3,065
NERC	884,468	1,033,578	16.9	14.4	51,145	1,084,723

[3] An uncommitted resource within a region is capacity not contracted to serve demand, capacity that does not have adequate firm transmission to be deliverable, or capacity for which transmission studies have not been conducted to determine if the capacity is deliverable.

[4] Resources within a region could be either existing (installed) or planned, for both planned capacity and uncommitted resources. In the near term, most of the resources would be existing, while in the longer term a larger portion would be planned.

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

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

Region	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Planned Capacity Resources Reserve Margin (%)	Planned Capacity Resources Capacity Margin (%)	Uncommitted[6] Resources (MW)	Total[7] Potential Resources (MW)
Winter – 2006/2007						
ECAR	90,526	133,243	47.2	32.1	780	134,023
FRCC	44,608	55,597	24.6	19.8	2,454	58,051
MAAC	47,230	71,379	51.1	33.8	0	71,379
MAIN	41,811	68,656	64.2	39.1	2,679	71,335
MRO-U.S.	25,333	34,439	35.9	26.4	0	34,439
MRO-Canada	6,855	8,700	26.9	21.2	0	8,700
NPCC-U.S.	48,528	74,971	54.5	35.3	0	74,971
NPCC-Canada	64,062	73,978	15.5	13.4	0	73,978
SERC	145,256	187,312	29.0	22.5	41,813	229,125
SPP	29,575	49,265	66.6	40.0	9,302	58,567
Eastern Interconnection	543,784	757,540	39.3	28.2	57,028	814,568
WECC-U.S.	106,745	158,941	48.9	32.8	0	158,941
WECC-Canada	20,246	22,932	13.3	11.7	0	22,932
WECC-Mexico	1,495	2,573	72.1	41.9	0	2,573
Western Interconnection[8]	128,484	184,193	43.4	30.2	0	184,193
ERCOT Interconnection	41,772	71,927	72.2	41.9	0	71,927
U.S.	621,384	905,730	45.8	31.4	57,028	962,758
Canada	91,163	105,610	15.8	13.7	0	105,610
Mexico	1,495	2,573	72.1	41.9	0	2,573
NERC	714,042	1,013,913	42.0	29.6	57,028	1,070,941
Winter – 2010/2011						
ECAR	96,622	133,243	37.9	27.5	3,287	136,530
FRCC	49,625	61,307	23.5	19.1	2,454	63,761
MAAC	50,289	73,774	46.7	31.8	0	73,774
MAIN	44,799	72,187	61.1	37.9	5,121	77,308
MRO-U.S.	27,039	36,372	34.5	25.7	0	36,372
MRO-Canada	7,110	9,197	29.4	22.7	0	9,197
NPCC-U.S.	51,113	74,297	45.4	31.2	0	74,297
NPCC-Canada	66,010	74,935	13.5	11.9	19	74,954
SERC	155,109	195,046	25.7	20.5	35,414	230,460
SPP	31,629	50,707	60.3	37.6	9,302	60,009
Eastern Interconnection	579,345	781,065	34.8	25.8	55,597	836,662
WECC-U.S.	116,381	169,468	45.6	31.3	0	169,468
WECC-Canada	21,787	23,726	8.9	8.2	0	23,726
WECC-Mexico	1,853	2,918	57.5	36.5	0	2,918
Western Interconnection[7]	140,018	195,945	39.9	28.5	0	195,945
ERCOT Interconnection	45,823	73,923	61.3	38.0	0	73,923
U.S.	668,429	940,324	40.7	28.9	55,578	995,902
Canada	94,907	107,858	13.6	12.0	19	107,877
Mexico	1,853	2,918	57.5	36.5	0	2,918
NERC	765,189	1,051,100	37.4	27.2	55,597	1,106,697

[6] An uncommitted resource within a region is capacity not contracted to serve demand, capacity that does not have adequate firm transmission to be deliverable, or capacity for which transmission studies have not been conducted to determine if the capacity is deliverable.
[7] Resources within a region could be either existing (installed) or planned, for both planned capacity and uncommitted resources. In the near term, most of the resources would be existing, while in the longer term a larger portion would be planned.
[8] 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 Additions

More than 7,122 miles of new transmission (230 kV and above) are proposed for construction through 2008, with a total of 12,484 miles added over the 2005–2014 time frame. The increase represents a 5.9% increase in the total amount of installed transmission in North America over the assessment period. *Table 3* 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*

	2004 Existing	2005–2009 Additions	2010–2014 Additions	2014 Total Installed
ECAR	16,490	221	0	16,711
FRCC	6,898	360	81	7,339
MAAC	7,057	134	0	7,191
MAIN	6,201	523	234	6,958
MAPP-U.S.	14,715	384	423	15,522
MAPP-Canada	6,662	96	872	7,630
NPCC-U.S.	6,406	384	110	6,900
NPCC-Canada	28,961	375	335	29,671
SERC	28,945	1,210	815	30,970
SPP	9,955	14	21	9,990
Eastern Interconnection	132,290	3,701	2,891	138,882
WECC-U.S.	58,231	2,291	2,083	62,605
WECC–Canada	11,191	470	238	11,899
WECC–Mexico	638	145	0	783
Western Interconnection	70,060	2,906	2,321	75,287
ERCOT Interconnection	8,081	515	150	8,746
U.S.	162,979	6,036	3,917	172,932
Canada	46,814	941	1,445	49,200
Mexico	638	145	0	783
NERC	210,431	7,122	5,362	222,915

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

GENERATION AND TRANSMISSION ISSUES

Decommissioning of Uneconomic Generation

In many regions, there has been a significant amount of generation capacity added in the last several years, much of which has been efficient combined-cycle, natural gas-fueled generation. Although many old plants have seen increased utilization, some older generating units, which are both less fuel efficient and often subject to increasingly stringent environmental operating limits, are being operated less frequently. Owners of these plants have increasing motivation to retire, mothball, or otherwise remove this generation from service.

Some of this older, less efficient generation may be needed to support local transmission reliability. For these units, an evaluation should be conducted to determine whether the units should remain available to maintain reliability, at least in the short term, until transmission or alternative plans can be implemented. One alternative being implemented in some regions is the adoption of reliability must-run (RMR) contracts, which compensate generation owners for maintaining generation that might not be economically viable but is needed for reliability, e.g. to maintain voltage support or to mitigate congestion.

Transmission Investment

With the exception of those specific areas and problems identified in each of its seasonal and long-term reliability assessments, NERC generally expects the transmission system in North America to perform reliably during the 2005–2014 assessment period covered by this report. NERC recognizes that many industry observers and policymakers have cited the lack of transmission investment in recent years as a threat to the reliability of the bulk electric system. While the system has come under increasing strain over the past several years because of increased demand and tighter transmission operating margins, reliability can be maintained and should not be threatened if the industry adheres to the NERC reliability standards. If the reliability rules are followed, the system can operate reliably over the entire range of demands expected to be placed upon it.

When considering overall transmission investment, an important distinction should be drawn between transmission investments that are made for reliability purposes and investments that are made for economic purposes. The initial costs for transmission upgrades made for reliability purposes — that is, specifically to comply with reliability standards — are generally shared by all customers in a utility service area or market region. When investments for transmission upgrades are made for economic purposes — that is, to provide access to lower-cost supply or reduce congestion costs arising from the redispatch of generation — those costs are often shared between the customers benefiting from the upgrade and the new generating plant associated with that upgrade.

Over time, economic-based transmission upgrades become part of the essential reliability fabric of the bulk transmission system because of the collective need to relieve potential transmission constraints and minimize congestion. Similarly, transmission upgrades designed for reliability purposes can have economic and market benefits.

Assertions made regarding the lack of transmission investment, however, refer principally to the need to reduce the cost of transmission congestion and generation redispatch. NERC assessments focus on reliability. Although unresolved congestion could ultimately lead to reliability concerns, NERC assessments have found that the performance of the bulk transmission system continues to demonstrate that system operations are occurring within prescribed voltage, thermal, and stability limits.

The NERC assessments do acknowledge the economic realities and point out that some portions of the bulk transmission system do not support all desired market transactions. They also note that, as demand increases and as some bulk systems experience increased power transfers, certain parts of the system will operate closer to their reliability limits more frequently. Operating closer to the limits of system capability, however, does not necessarily threaten the reliability of the bulk electric system. Today's advanced analytical tools make it possible for system operators to more accurately assess system conditions and maintain system reliability even on a constrained system. If NERC reliability rules are followed, the transmission system can be operated reliably even under constrained conditions.

Future NERC assessments will continue to focus principally on the reliability issues associated with bulk transmission system adequacy. When appropriate, they will also acknowledge the market and economic consequences of constrained transmission paths.

Reliability of Off-site Power Sources for Nuclear Plants

Nuclear plant licensees are required by law to maintain an off-site power source with the capacity and capability to safely shut down their nuclear plants. Today, the nuclear plant licensee may not be affiliated with the owners of the transmission or the other generating assets required to maintain the plant's off-site supply. Ensuring that the transmission system is planned and operated to maintain the requirement of the off-site power source requires continual communication among the stakeholders.

Training of transmission and nuclear plant operators and effective communication among them are key to meeting a nuclear plant's unique off-site source requirements. The potential for a degraded grid or notification of a transmission contingency that could lead to a nuclear plant shutdown have unique requirements that must be factored into transmission planning and operations. NERC is developing a standard to address this issue.

Greenhouse Gas Emissions

The long-term implications of greenhouse gas (GHG) emissions policies on the adequacy of future electricity supply are a function of the degree to which such policies and regulations limit or reduce the principal power plant sources of GHG emissions — carbon dioxide (CO_2) and nitrous oxide (N_2O) — and thereby limiting electricity production from fossil fuels.

The resulting influence of federal, state, and provincial regulation of GHG emissions on the combustion of fossil fuels for power generation could restrict electricity production in the 2005–2014 assessment period. The potential reliability impacts of GHG limits on fossil-fueled power generation will depend on the transition period for coming into compliance with any new regulations.

Clean Air Mercury Rule

The Environmental Protection Agency (EPA) promulgated its first rule regulating mercury emissions on March 15, 2005. The rule has requirements for both new and existing units. New units have to meet strict emission limits contained in new source performance standards (NSPS), while both new and existing units have to hold sufficient allowances to cover their emissions. Each state will be given a budget of emission levels to allocate as they see fit. They can participate in a nationwide trading program similar to the acid rain program, or they can choose their own methods of meeting their budgets. They have the option of holding back some allowances for new units.

Combustion turbines are included in the state budgets of emission levels, but are not required to meet the NSPS limits.

The national cap on mercury emissions is 38 tons per year beginning in 2010 (this is up from 34 tons per year in the proposed rule) and 15 tons in 2018. EPA expects the former limit to be met by co-benefits from the Clean Air Interstate Rule (CAIR) and that mercury specific reductions will be needed only to meet the 2018 limits. Allowances can be banked immediately after being issued by the states, which have 18 months to develop their plans. Reductions are expected to start earlier than 2018. These emission limits could lead to early retirement of older generating units, and should be evaluated for potential effects on capacity margins. The reliability impacts, if any, associated with these new rules are unclear at this point. NERC will continue to monitor the implementation of these rules and include any impacts in its future assessments as appropriate.

Gas/Electricity Interdependency

Over the past several years, natural gas has been the fuel of choice for the majority of new generating capacity additions, particularly for generating units designed to provide intermediate and peaking capability. Three main issues have been identified with natural gas-burning generating units that could jeopardize reliability: fuel diversity, fuel deliverability, and fuel availability.

Fuel diversity could be an issue because a lack of diversity in fuel supply makes overall generating capacity dependent on certain fuels and, as a result, vulnerable to disruptions in the supply of those fuels. If units are fueled by a diversity of fuel supplies, a disruption in any one of those fuels would not have an overwhelming consequence on available generation capacity.

In some regions, an increase in natural gas usage tends to increase the diversity of fuel types while in other regions it reduces fuel diversity. In general, greater fuel diversity increases the overall probability of having adequate generating capacity.

Because the operating reliability of the infrastructure that delivers natural gas to the generating stations is limited in some areas, fuel deliverability could be affected. An assessment of reliability must consider the operating reliability of the gas infrastructure.

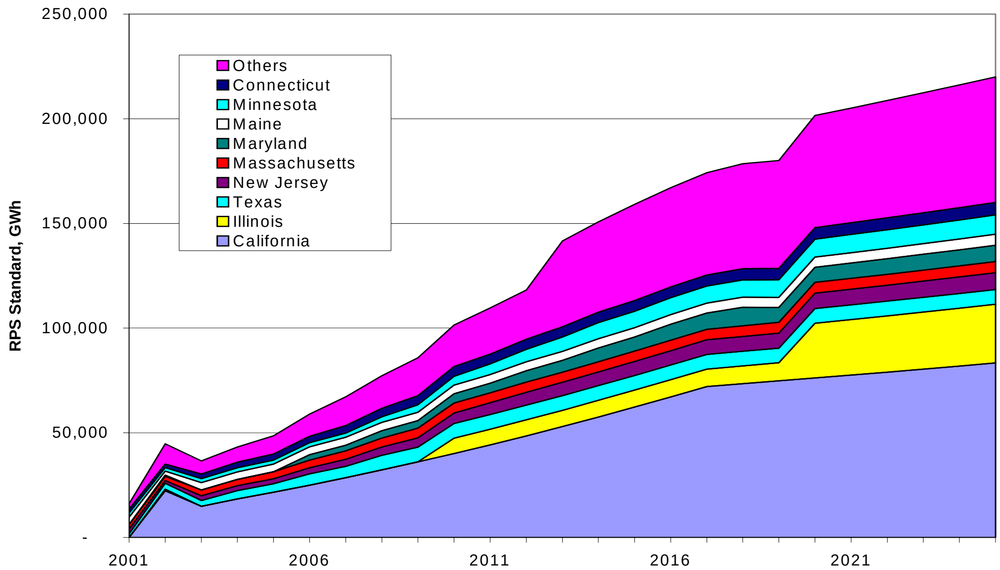
NERC established the Gas/Electricity Interdependency Task Force (GEITF) to identify the magnitude of the fuel delivery problem and recommend a course of action. The GEITF issued the report *Gas/Electricity Interdependencies and Recommendations* in June 2004, which evaluated the interdependency between gas pipeline operation and planning, and electric system operation and planning reliability over the next ten years.

The report contained a list of seven recommendations designed to mitigate the reliability impacts of the interdependency between the gas pipeline industry and the electric industry. These recommendations focus on the following issues: regional assessments of the impact of fuel transportation interruption on electric system reliability; increased communications between pipeline operators and NERC reliability coordinators; coordination of planned gas pipeline outages with electric system requirements; development of reliability standards that address the analysis of gas delivery contingencies; and development of standards that address gas delivery infrastructure. These recommendations have been assigned to various NERC groups for implementation.

Potential Renewable Portfolio Standards

Currently, a total of eighteen states and the District of Columbia have adopted renewable portfolio standards (RPS) for the purchase of energy. Generally, the RPS obligation is imposed on load-serving entities and usually requires them to procure between 1 and 20% of their electricity supply from renewable sources — wind, solar, biomass, geothermal, hydro, and to a lesser extent, wave/tidal, landfill gas, and municipal or biomass-based waste.

Figure 14: Status of Renewable Portfolio Standards



Source: EVA

Because renewable sources of electric power are intermittent in nature, actual generating capacity available at times of peak demand is less predictable than it is for capacity produced from more traditional fuels. Another concern is that these resources are generally energy limited (meaning that the actual electricity produced in relation to the available capacity is relatively small). Although a large amount of capacity based on peak output may be planned, the effect is that these resources would have a relatively low level of MW-hours produced. This result can be considered relative to both dimensions of reliability — supply adequacy and operating reliability.

From a supply adequacy and operating reliability perspective, the characteristics of the intermittent and energy-limited renewable resources would require that sufficient dispatchable resources and transmission capacity be available to assure resource adequacy at all times.

Further, renewable resources need to be analyzed from the standpoint of their ability to maintain ratings that would need to be within the capacity of local transmission facilities, and from the need to possess, for example, adequate levels of reactive power capability, voltage regulation, and low-voltage ride-through capability, which would allow such generation to remain connected to the bulk system under low-voltage conditions.

Uncommitted Generation Resources

NERC distinguishes between different classifications of generation for assessment purposes and how they contribute to reserve and capacity margins. Planned committed resources are generating resources that are existing or planned in a given region (including purchases, but excluding sales and the capacity required to supply station service or auxiliary needs) that can sustain a maximum level of production over a specified period. Uncommitted resources are generating resources that are built, planned, or in operation, but that:

1. Have not been contracted to serve demand;
2. Do not have firm transmission service reserved to guarantee deliverability throughout the region; or
3. Have not had a transmission study conducted to determine their level of deliverability.

In the NERC seasonal assessments, reserve and capacity margins are calculated for both committed and uncommitted resources because the time frames are short and because the vast majority of power plants in question have been built and are capable of operation.

Uncommitted resources are generally merchant power plants that have been built to sell wholesale electricity to utilities in a given region that, in turn, sell to their retail customers. In many regions, both merchant and regulated plants constitute planned capacity resources, so reserve and capacity margin calculations are identical.

If all uncommitted resources are included in the calculations, the reserve and capacity margins will be overstated because not all existing uncommitted capacity is 100% deliverable to retail load in the region (the same is true of committed resources, but to a lesser degree). Similarly, if none of the existing uncommitted resources are included in the calculations, then the reserve and capacity margins reported will be understated.

For future assessments, the RAS, Data Coordination Working Group (DCWG), and Planning Committee will work on definitions and methods of determining how to treat uncommitted resources.

FIDVR/Short-Term Voltage

Fault-induced delayed voltage recovery (FIDVR) is a transient short-term voltage condition in which the system voltage stays at low levels for several seconds after a transmission fault has been cleared, and may be accompanied by loss of load and even generation. Heavily loaded induction motors (such as air conditioning equipment) subjected to low voltages tend to slow down and increase their reactive power consumption, thus aggravating the low voltages created by the initial fault activity. In a worst-case scenario, FIDVR may even evolve into short-term voltage instability.

During periods of high demand, traditional operational assessments may indicate that the system is secure. But in reality, there may be single contingency or credible multicontingency fault scenarios, which could cause a FIDVR event that would result in local or wide-area loss of load and generation. Because traditional operational assessments may not always indicate problems, transmission planners should assess their system for exposure to FIDVR events and utilize those assessments to determine strategies to mitigate the effects of FIDVR. Mitigation strategies could include transmission reinforcements, safety-net schemes, and the development of operational guidelines.

REGIONAL SELF-ASSESSMENTS

ECAR

ECAR, MAAC, and MAIN are working toward the formation of a larger regional reliability council, ReliabilityFirst Corporation, which will replace ECAR, MAAC, and portions of MAIN with a single council, RFC. RFC is tentatively scheduled to begin operations by January 1, 2006. The planning and operational policies and procedures of RFC will supersede the policies and procedures of the existing three regions.

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. AEP has started construction on its 765-kV transmission line in southeastern ECAR, which is expected in service in mid-2006 and is needed to guard against potential widespread interruptions.

The region's criteria for resource adequacy will be satisfied through at least 2013, based on the assumption that capacity resources of up to 5,550 MW are available outside the ECAR region when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years.

Demand

Throughout the 2005–2014 assessment period, the annual peak for total internal demand in the ECAR region is expected to continue to occur during the summer. Over the 2005–2014 period, a 1.8% average annual demand growth is expected, the same as the average growth rate in last year's projection. The first five years of the assessment period are projected to have a higher growth rate of 2.15%, slightly more than last year's 2.11% demand growth projection for the first five years. This peak demand growth is based on forecast economic factors and average summer weather conditions; so actual peak demands may vary significantly from year to year. The 2005 forecast is 8.8% above the 2004 actual.

Current resource projections developed by ECAR members indicate that direct-controlled and interruptible load-management programs will provide 2,400–2,500 MW of supplemental resources during the 2005–2014 assessment period. With interruptible demand and loads under demand-side management removed, ECAR's net internal demand is projected to be about 119,000 MW in 2014.

Resources

ECAR's Generation Resources Panel (GRP) annually conducts an extensive probabilistic assessment of long-term capacity margin adequacy. The assessment considers the regional peak demand profile, the recent availability of ECAR member generation, and both the existing and projected regional generating capacity. The most recent GRP *Assessment of ECAR-Wide Capacity Margins* can be downloaded from ECAR's Web site at www.ecar.org.

Two reliability measures are used to assess the adequacy of ECAR-wide capacity margins. The dependence on supplemental capacity resources (DSCR) measure is used to assess the adequacy of ECAR capacity margins on an isolated "ECAR-alone" basis. The loss of load expectation (LOLE) measure is used to assess the ECAR capacity margin when the import capability is included.

The historic criterion used by ECAR to assess the adequacy of ECAR-wide capacity margins is the DSCR index, expressed in days per year of expected capacity deficiency. A DSCR index for the ECAR region of one to ten days per year is currently consistent with marginal but satisfactory regional power supply adequacy for the assessment period.

Based on analysis by ECAR's Generation Resources Analysis Working Group (GRAWG), ECAR's one-to-ten days DSCR was determined to be consistent with an LOLE of one day in ten years, or 0.1 day per year, in a multiregional assessment. This criterion of 0.1 day per year LOLE is used to assess the adequacy of ECAR capacity margins that include the import capability. Based on its transmission system assessments, ECAR's Transmission System Performance Panel (TSPP) has estimated the ECAR region's import capability at 5,550 MW for use in this assessment.

ECAR members develop ten-year capacity projections that reflect the capacity resources necessary to reliably serve demand and energy for their companies. In addition, nonmembers have announced intentions to construct a number of generation projects in the region. When the nonmembers' announced-capacity projects and member plans are combined, the net demonstrated capacity is projected to increase by about 550 MW during 2005. The total announced increase in generating capacity is about 3,300 MW by 2014. About 1,600 MW of this potential capacity increase from 2005 through 2014 is in the form of combustion turbines and combined-cycle plants that are likely to use natural gas for fuel.

Because the construction status of many near-term capacity projects will not be known until they are nearly in service, and later projects are not yet under construction, the timing and amount of new capacity additions is uncertain, and consequently, the expected ECAR capacity margins. Capacity margins in ECAR, which include the announced additions after 2005, would range from a high of 20% in 2005, declining to 9% in 2014, based on net internal demand. This compares to 21% in 2004, declining to 13% in 2013 from last year's assessment. Capacity margins, without including announced additions after 2005, would decline over the next ten years from 20% in 2005 to a low of 6% in 2014, based on net internal demand. These margins in last year's assessment for 2004–2013 were 20 and 6%, respectively.

The magnitude of the variation in expected capacity margins illustrates the uncertainty faced by the region in assessing the adequacy of its resources. Because of this uncertainty in capacity resources, the analysis carried out in the ECAR assessment does not include any announced or planned capacity after 2005. It also does not include any purchases or sales. Instead, the analysis is conducted to indicate the amount of capacity or additional import capability that might be needed to achieve an acceptable level of reliability.

Using both reliability measures indicated above, the ECAR assessment indicates that through 2009, there will be no additional need to supplement the capacity presently in service or expected in service in 2005. This conclusion is based on the assumption that 5,550 MW of capacity resources will be available outside the ECAR region when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years. ECAR has not explicitly analyzed the amount of capacity needed to meet its reliability criteria beyond 2009.

The recent decline in announced capacity additions has stabilized the capacity fuel mix percentages. Coal is the predominant fuel used within the ECAR region and is expected to fuel about 63% of the generating capacity from 2005 through 2014. Natural gas is used by about 26% of the capacity in the region throughout this same period.

As a result of the substantial increase of natural gas generation in ECAR in the past four years, ECAR is monitoring the natural gas supply for indications of possible supply constraints. ECAR is not aware of any specific long-term fuel supply or fuel infrastructure problems that would adversely impact regional reliability.

Transmission

The transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required. Throughout ECAR, local transmission overloads are possible during some generation and transmission contingencies. However, ECAR members use operating procedures to effectively mitigate such overloads.

Current ECAR member plans during the assessment period call for the addition of about 221 miles of EHV transmission lines as well as five substations that are expected to enhance and strengthen the bulk transmission network. Most of those additions are connections to new generators or substations serving load centers. Depending upon specific dispatch patterns of new and existing generation, the output of all planned generation may not be fully deliverable because of transmission limitations.

One major project included in these planned additions is the AEP Wyoming-to-Jacksons Ferry 765-kV transmission line. This line was originally proposed for service in May 1998, and is now expected to be completed in June 2006. A tri-regional (ECAR, MAAC, and SERC) assessment of the reliability impacts of this project concluded that the project's delay has caused a reliability risk. Operating procedures have been used to minimize the risk of widespread interruptions until the project is completed.

ECAR also has two other planned transmission line additions. Duquesne Light plans to add a 12-mile, 345-kV line by 2009 in the eastern part of its system; the line is being added to relieve line loading, and provide contingency relief and local voltage support. East Kentucky Power Cooperative will add, by the summer of 2009, a 345-kV loop into its J. K. Smith power station from the Avon-Spurlock line to provide needed transmission capacity for new generation at the Smith plant.

ECAR actively participates in the MAAC-ECAR-NPCC (MEN), MAIN-ECAR-TVA (MET), and VACAR-ECAR-MAAC (VEM) interregional transmission assessment efforts. Transfer capability results for ECAR are included in each of the interregional seasonal reports.

Due to the blackout of August 14, 2003, ECAR recommended and has instituted a peer review process to ensure that ECAR's transmission owners and operators have conducted sufficient planning analyses and to complement its own assessment efforts. Since the blackout, the ECAR TSPP has conducted three peer reviews of member transmission assessments: two for the summer seasons and one for the long term. All assessments included both thermal and voltage analyses for base- and stressed-case conditions with single, double, and if warranted, extreme contingencies. The results of these assessments are communicated to ECAR's reliability coordinators and transmission operators. Transmission owners and relevant regional transmission organizations (RTO) are performing the necessary follow-up work.

To satisfy the U.S.-Canada Power System Outage Task Force blackout Recommendation 15 D 2, the ECAR TSPP conducted one-day site audits at its members' premises. Those audits traced circuit data from its origin in the member's rating methodologies through the planning power flow base-case models through the operation's energy management systems (EMS) and state estimator data to their respective reliability coordinator's EMS and state estimator data. Twenty items were checked for facility rating methodologies, processes, and data. Examples of excellence from those audits will be shared and policy and procedure changes may be made to address recommendations for improvement.

Since the blackout, the ECAR TSPP has increased the number of transfer scenarios studied in its seasonal assessments from 62 in 2003 to more than 350 for the summer of 2005. The number of voltage analyses increased from about 14 in 2003 to more than two dozen for the summer of 2005. ECAR continues to work toward addressing all of the blackout recommendations from all sources.

Operations

The Midwest Independent Transmission System Operator (MISO), PJM Interconnection, and Tennessee Valley Authority (TVA) are performing the reliability coordinator functions for all of the ECAR balancing authorities and transmission operators.

One major transmission addition is planned in the future that will affect operations in the ECAR region. As discussed above, the addition of the AEP 765-kV transmission line from the Wyoming station to the Jacksons Ferry station will strengthen the transmission system and eliminate the use of complex operating procedures.

By the end of 2005, all of the ECAR balancing authorities and two of the three reliability coordinators will have completed an audit under the NERC Readiness Audit Program. The remaining reliability coordinator is scheduled to complete its NERC readiness audit in 2006. Numerous operational improvements have been implemented as a result of the readiness audits. The most widespread of these operational improvements dealt with improved emergency and restoration training, improved security analysis procedures and programs, and improved communications between and among reliability coordinators, balancing authorities, and transmission operators.

Environmental restrictions on nitrogen oxides (NO_x) emissions could, under certain conditions, curtail the availability of capacity and energy from generating units within ECAR.

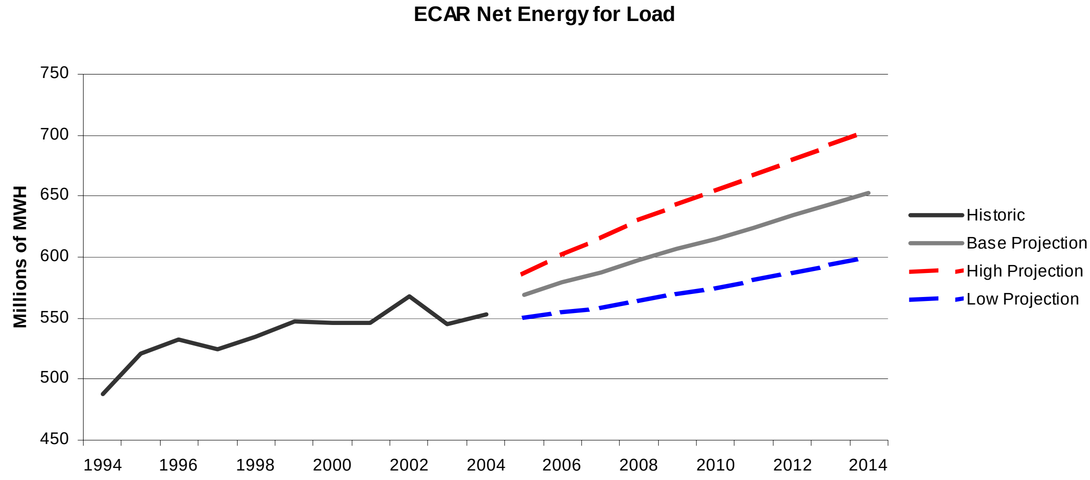
Assessment Process

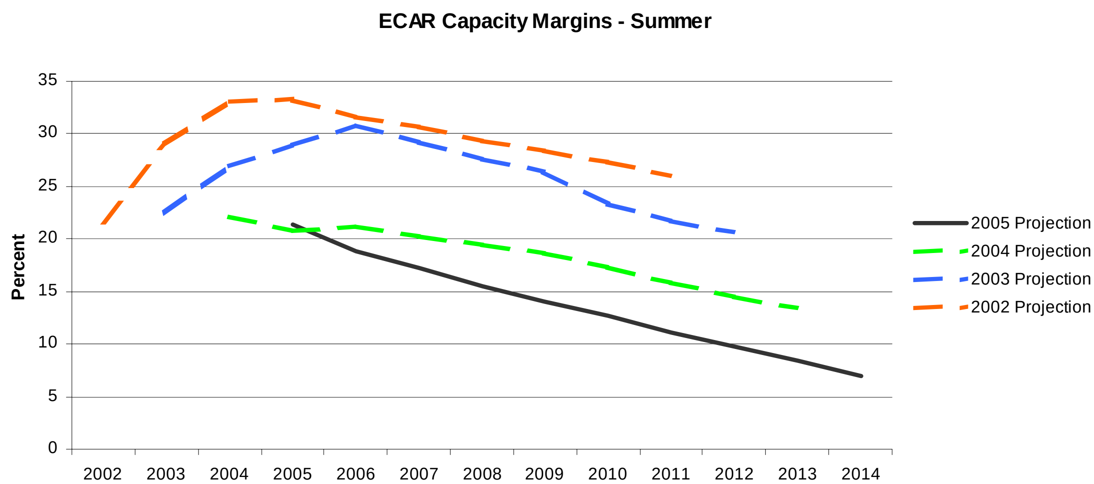
ECAR assessment procedures are applied to all generation and transmission facilities that might significantly impact bulk electric system reliability. These assessments consider ECAR as a single integrated system. The operating reliability impact of interactions with neighboring regions is assessed by participation in the MEN, VEM, and MET interregional groups. Generation resource assessments of the ECAR systems on a region-wide basis are performed annually for a planning horizon of up to ten years, and semiannual 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 actions to be taken.

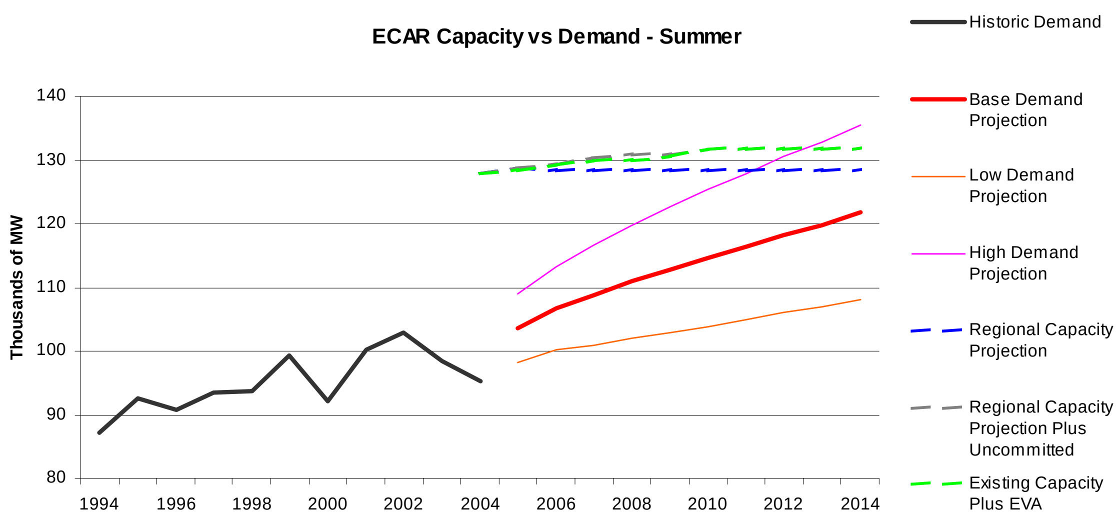
In ECAR, each individual company along with its RTO performs planning analyses for facility additions. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected demand, given the proposed changes or additions to generation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

ECAR, MAAC, and MAIN are working toward the formation of a larger regional reliability council, ReliabilityFirst Corporation (RFC), which would replace ECAR, MAAC, and portions of MAIN with a single council, RFC. The RFC is tentatively scheduled to begin operations by January 1, 2006. The planning and operational policies and procedures for the RFC will supersede the policies and procedures of the existing three regions. The ECAR membership currently consists of 22 full members and 16 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.

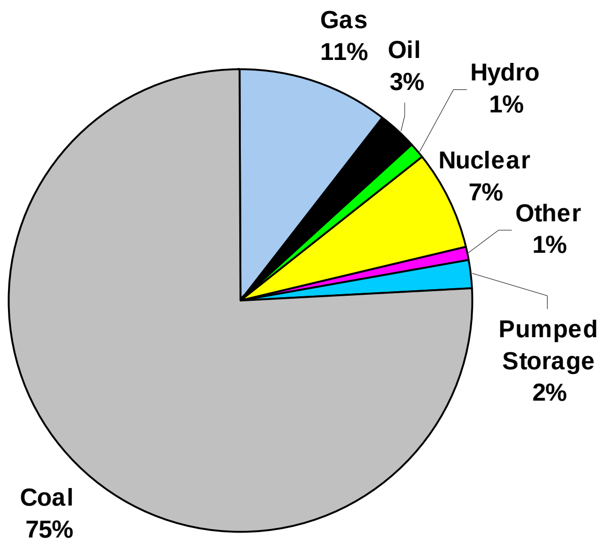
ECAR Capacity and Demand



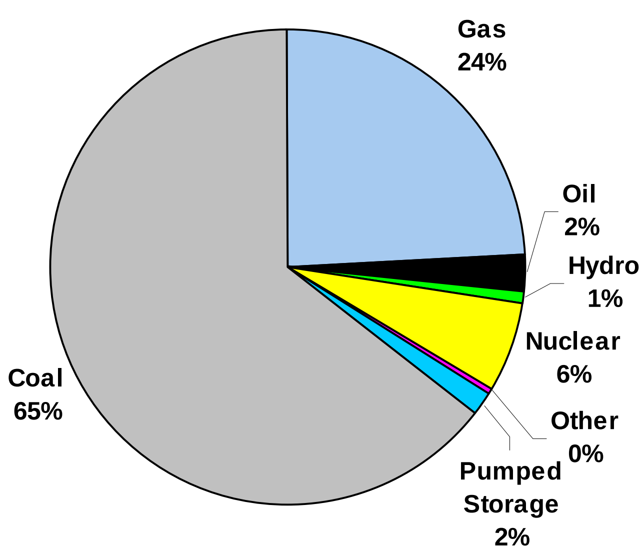




ECAR Capacity Fuel Mix 2000



ECAR Capacity Fuel Mix 2010



ERCOT

ERCOT is an electric interconnection with a single reliability coordinator and balancing authority. ERCOT's primary mission is threefold: 1) to maintain a reliable interconnection; 2) to facilitate a fully competitive wholesale electricity market; and 3) to enhance the ability of retail customers to choose their electric supplier.

ERCOT recently made improvements to its long-term load forecasting methodology and further defined how it determines resource adequacy. These changes, along with the mothballing of additional generation capacity, result in lower capacity margins than previous assessments have shown, particularly for the near term. Capacity margins are expected to be near, but above, the minimum requirement of 11% until 2010. Given ERCOT's primary dependence on natural gas-fueled generation, the future adequacy of natural gas supply during extended periods of cold weather remains a concern.

ERCOT continues to make improvements to the transmission system that is expected to reduce the need for congestion management actions while maintaining system reliability. More than 500 miles of 345-kV transmission lines are planned to be put in service between 2005 and 2010 along with a significant amount of lower voltage transmission. This new transmission will serve to meet reliability requirements and enable more economical dispatch of generation.

Demand

ERCOT has reduced its projected average annual demand growth rate over the assessment period from 2.4% used last year to 1.8% for this year's assessment. The reduction is due to the historical trend of declining growth rates and ERCOT changing its load forecasting methodology to an econometric model that also takes into account economic and weather variables. With an expected growth rate of 1.8%, capacity margins for the period are projected to be above the regional minimum requirement of 11% until 2010. ERCOT does not maintain resource forecasts beyond the next five years.

The actual peak in 2004 of 58,531 MW was 4.7% less than forecast and 2.4% less than the 2003 all-time peak demand, largely due to a milder than usual summer in 2004. Projected peak demand for 2005 is 60,475 MW and 71,113 MW for 2014. These projected demands include 1,150 MW of load that could be interrupted if needed to reduce demand.

ERCOT has two direct current ties to SPP and one to Mexico with a total capacity of about 856 MW. A generator in ERCOT that is owned by entities in SPP has a 189 MW transfer out of ERCOT. This transfer is treated as a long-term sale in ERCOT reliability analyses.

Resources

ERCOT has set 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, which concluded that the margin should provide an LOLE of about a one day in ten years.

In conjunction with improving the load forecast methodology, ERCOT further defined what resources could be counted to meet demand and reserve margin requirements. Resources that are counted include:

- Existing in-service capacity based on demonstrated summer net dependable capacity (except for wind generation and switchable capacity that has the capability to switch between ERCOT and other interconnections);

- Future planned generation with signed interconnection agreements;
- Fifty percent (currently 420 MW) of dc tie capacity;
- Switchable capacity to the extent the owners have indicated they intend to be in the ERCOT market;
- Based on historical performance on peak, 2.9% of existing in-service wind capacity and future wind capacity with signed interconnection agreements; and
- Mothballed capacity based on when the owners estimate the capacity will be returned to service.

ERCOT is projecting about 6,000 MW less installed capacity over the 2005–2014 assessment period than it did in last year's assessment, mainly due to additional unit retirements and mothballing occurring over the last year. This results in much lower capacity margins than last year's assessment indicated, particularly for the near term, even with the reduction in forecast demand. Margins are projected to be in the low teens rather than the low twenties. However, the assessment indicates capacity margins should remain close to, but above, the 11% minimum requirement until 2010. The Public Utility Commission of Texas (PUCT) is in a rule-making process to determine what mechanisms should be used to ensure maintaining the minimum capacity margin in ERCOT going forward.

Generation owners are required to provide ERCOT advance notice of extended planned shutdowns of generation so ERCOT can enter into RMR contracts for those units to keep them available if needed for system reliability. ERCOT currently has contracts with 1,411 MW of RMR capacity in the Laredo, Corpus Christi, Rio Grande Valley, and Houston areas that is needed to provide local voltage support and keep transmission facility loadings below limits. ERCOT has exit strategies to improve the transmission system so this RMR capacity can be phased out over the assessment period.

ERCOT expects 1,752 MW of new generating capacity to come on-line between 2005 and 2010. The new capacity consists of 500 MW coal, 660 MW gas, and 592 MW wind. ERCOT does not maintain a new generation forecast beyond 2010.

Entities in ERCOT anticipate importing via the DC ties about 120–136 MW of firm purchases over the assessment period.

The future adequacy of natural gas supply given the large amount of new and existing generation capacity dependent on that fuel is a continuing concern, primarily during periods of extended cold weather. Natural gas-fueled resources account for almost 70% of the installed capacity in ERCOT, and that percentage is not expected to change significantly over the assessment period. Currently no market incentive or nonmarket mechanism is in place for gas generation to maintain dual-fuel capability and storage, typically with fuel oil, which could be critical to maintaining generation adequacy during extended periods of gas curtailments. ERCOT will initiate its emergency electric curtailment plan (EECP) if available capacity gets below required levels due to gas curtailments or any other reason. The EECP maintains the reliability of the interconnection by avoiding uncontrolled load shedding.

Energy

The forecast growth rate in energy usage over the next ten years is 2.1% per year, little changed from the 2.0% growth assumed in last year's forecast and the long-term historical growth rate.

Transmission

The major transmission constraints in ERCOT are due to:

- Transfers into the Dallas-Fort Worth area from northeast and central Texas;
- Transfers into Houston from northern and southern Texas;

- Transfers out of the west Texas wind generation area;
- Transfers into and across the Rio Grande Valley; and
- Local security needs in Corpus Christi and Laredo.

These constraints have required the frequent redispatch of generation by ERCOT and establishing RMR contracts with generators that would have otherwise shut down as previously discussed. The consequence has been an economic cost to the market, as ERCOT has had to operate older, less efficient generation due to transmission constraints instead of newer more efficient generation in order to meet reliability criteria.

A number of new 345- and 138-kV lines are under construction in the Dallas-Fort Worth area, western, central, and southern Texas that will provide relief for these constraints and will allow ERCOT to exit RMR contracts. These improvements are also planned to eliminate most of the existing remedial action plans (RAPs) and special protection systems (SPSs) that have been put in place to temporarily reduce redispatch for congestion management. More than 500 circuit miles of major new 345-kV lines are scheduled to be in service between 2006 and 2010 to relieve these constraints.

A potential challenge in the assessment period could be accommodating a large increase in wind generation. By the end of 2005, there will be more than 2,000 MW of wind generation in west Texas. The sparse transmission system in west Texas has required frequent limitation of the output of this renewable generation resource while significant additional transmission is being constructed to accommodate its full output. The Texas Legislature has passed legislation that would mandate an additional 3,000 MW of wind generation by 2015. This would require significant additional transmission additions beyond those already in progress, particularly if most of this additional wind generation is also located in west Texas.

Transmission planning is increasingly using voltage and transient stability analysis. Voltage stability has become a more pressing concern with increasing power transfers in ERCOT and lessons learned from the August 2003 blackout.

Operations

Ongoing operational challenges during the assessment period are expected to center around transmission congestion management. In the short term, there are a number of temporary post-contingency RAPs and SPSs that maximize transfers over the existing system and reduce redispatch but require special operator attention.

Capacity margins, while still expected to be at or above minimum requirements, will decline over the assessment period from the relatively high levels experienced over the last few years. This, coupled with resource vulnerability to winter gas curtailments previously discussed, could increase the likelihood that operators will need to initiate emergency procedures such as the EECP in the future. ERCOT plans to have an operator training simulator available in 2006 to train operators on simulated EECP and other unusual events.

ERCOT operators started hour-ahead voltage stability analysis in the summer of 2005. This analysis will address one of the recommendations from the report on the 2003 blackout. In addition, ERCOT operations engineers will be able to perform hour-ahead transient stability analysis in late 2005, and ERCOT expects that the operators will be able to do so in 2006.

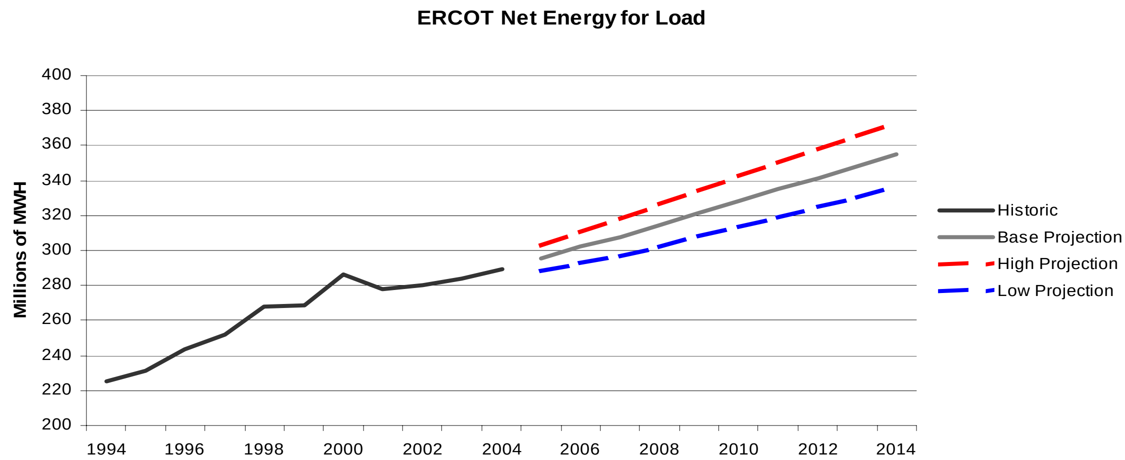
The PUCT is considering a major market redesign that would change current congestion management procedures from a zonal to a more nodal-based system. This transition would present challenges in implementing new operating systems, but could also improve the efficiency of transmission congestion management.

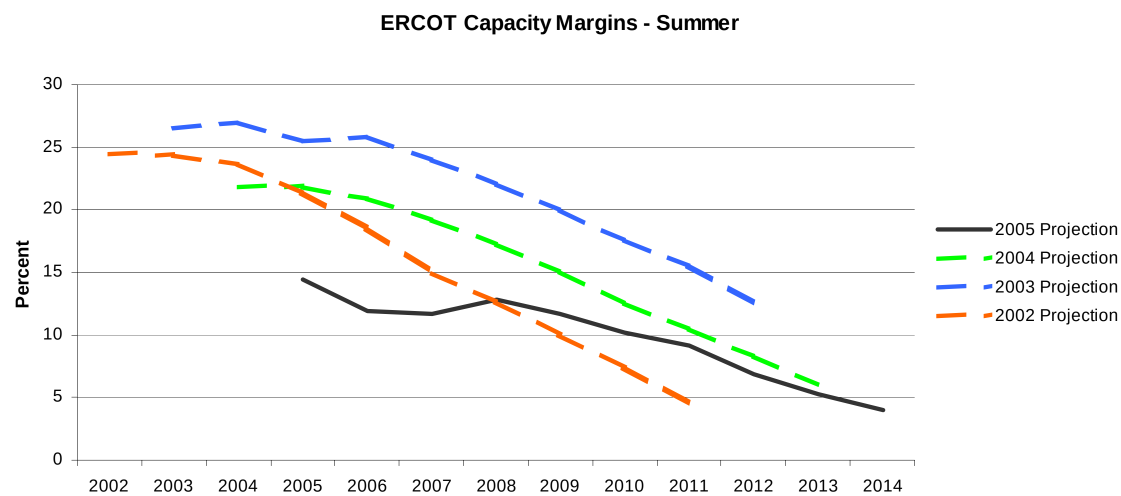
Assessment Process

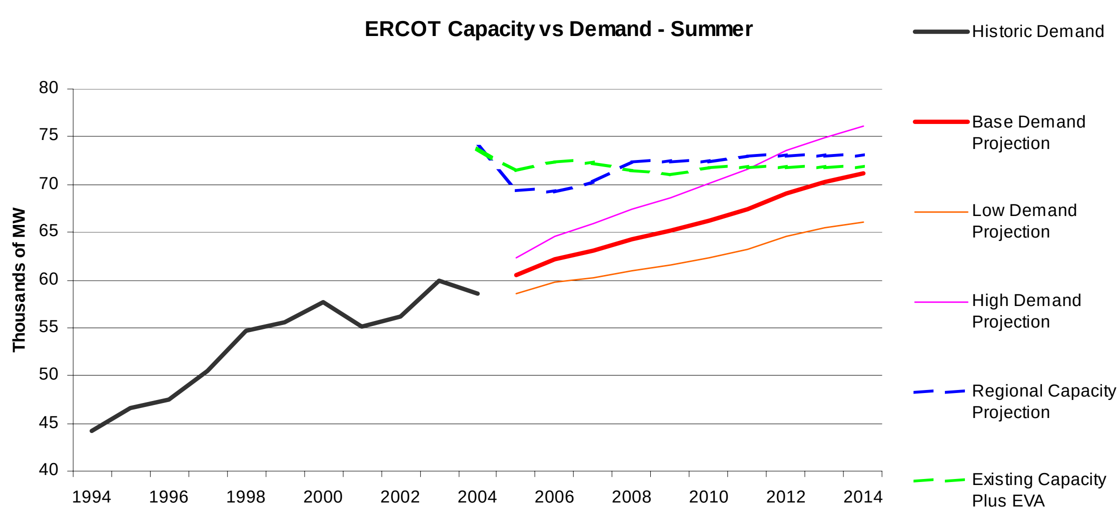
ERCOT prepares five- and ten-year projections of capacity, demand, and reserves at least annually to evaluate if the system will meet the capacity margin requirement of 11%. ERCOT also performs power-flow studies required to assess compliance with ERCOT planning criteria, which comply with NERC reliability standards. An annual study and report is made to the PUCT, with emphasis on congested areas of the transmission system and recommended projects to mitigate that congestion. ERCOT facilitates an open planning process through three regional planning groups made up of transmission owners and operators and other ERCOT market participants. Any party can comment on ERCOT planning studies and propose new projects or additional studies for review by the appropriate regional planning group.

ERCOT is a separate electric interconnection located entirely in the state of Texas. ERCOT has 135 members that represent independent retail electric providers; generators, and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85% of the electric load in Texas. ERCOT serves a population of more than 20 million in a geographic area of about 200,000 square miles with more than 69,000 MW of generating capacity and 38,000 miles of transmission lines.

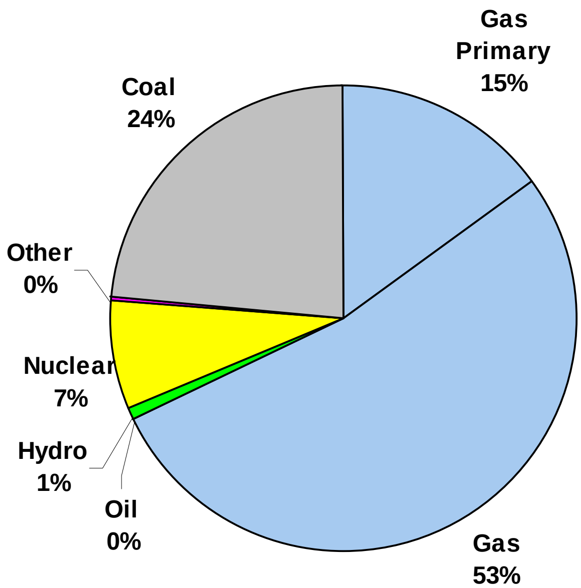
ERCOT Capacity and Demand



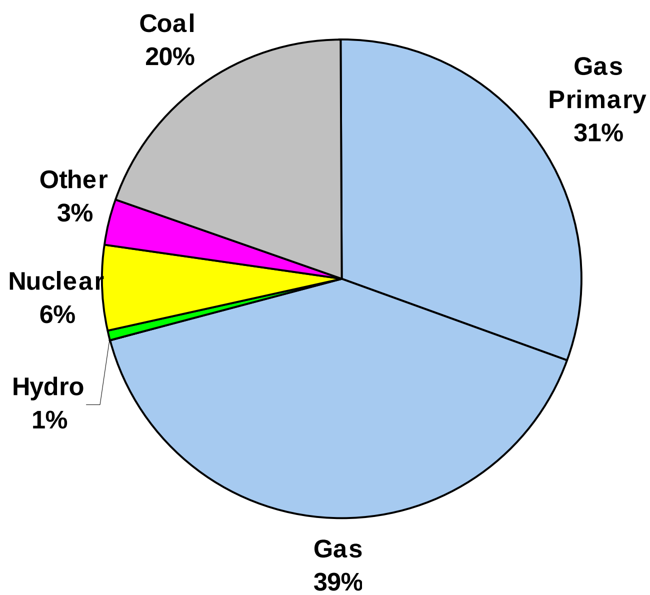




ERCOT Capacity Fuel Mix 2000



ERCOT Capacity Fuel Mix 2010



Gas primary capacity has dual fuel capability, but might not have the infrastructure or inventory to burn other fuels.

FRCC

FRCC expects to have adequate generating capacity reserves and transmission system capability throughout the 2005–2014 assessment period. Historically, FRCC has high-demand days in both the summer and winter seasons. However, because the region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer; this report will address the summer demand values.

FRCC adopted a high-level methodology to assess its natural gas pipeline and electric interdependency and concluded that it will have adequate natural gas-pipeline capacity into the region for the next five years. FRCC members use historical weather data bases consisting of as much as 56 years of data for the weather assumptions used in their forecasting models.

Demand

The 2005 ten-year demand forecasts for the FRCC region exhibited similar growth trends to 2004 projections. The expected 2005 summer total peak demand is 43,495 MW, compared with actual 2004 summer peak demand of 42,243 MW. The annual net peak demands for the summer months are projected to rise at a compounded average annual growth rate of 2.7% over the next ten years.

Resources

The Florida Public Service Commission (PSC) requires all Florida utilities to file an annual ten-year site plan that details how each utility will manage growth for the next decade. The data from the individual plans is aggregated into the FRCC *Load and Resource Plan* that is produced each year and filed with the PSC. The FRCC 2005 Load and Resource Plan shows FRCC reserve margins over the winter and summer peaks for the next ten years to equal or exceed 20% except for the summer peaks of 2008–2010, which are projected to be 19%. All years are well above the 15% reserve margin standard established by FRCC. The calculation of reserve margin does not include any merchant generating capacity that has not been firmly contracted by the load-serving entities.

FRCC members are projecting a net increase of 17,740 MW of installed capacity over the next decade. Of this increase, 13,766 MW are designated for gas-fired operation in either simple- or combined-cycle configurations, and 3,508 MW are anticipated for coal-fired operation. Gas-fired generation continues to dominate a high percentage of new generation. FRCC forecasts that electrical energy produced from natural gas generators will increase from 30% in 2004 to 45% in 2014.

Existing merchant plant capability in the FRCC region is 4,921 MW, of which 2,838 MW are under firm contract. The planned construction of merchant plants has decreased significantly over prior years' projections, and the amount of merchant generation that may come on-line in the next ten years depends on a number of factors that cannot be forecasted 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.

Energy

The 2005 ten-year energy forecast for the FRCC region displayed growth similar to the 2004 forecast. Yearly energy consumption is expected to rise by 2.8% over the next decade, slightly outpacing last year's projected ten-year annual growth of 2.5%.

Transmission

FRCC performed transmission studies for the 2005 summer period and for the 2005–2014 ten-year period. The studies showed that operational procedures successfully mitigated any reliability concerns in the first five years. In the long term, potential violations of planning criteria can be resolved by planned transmission projects since adequate time remains to monitor trends and construct required network upgrades. None of the problems are considered significant to the reliability of the system.

Interregional transmission studies are performed each year to evaluate the transfer capability between the Southern Company subregion of SERC and FRCC for the upcoming summer and winter seasons. Joint studies of the Florida/Southern transmission interface have verified the current summer import capability of 3,600 MW into the FRCC region, and the summer export capability of 1,300 MW. Currently, 1,552 MW are being imported into the region on a firm basis and about 839 MW are dynamically dispatched out of the Southern Company subregion.

Currently, individual members plan to construct 441 miles of 230-kV transmission lines during the 2005–2014 assessment period.

Operations

FRCC has a security coordinator agent (reliability coordinator) that monitors real-time system conditions and evaluates near-term operating conditions. The security coordinator uses a region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are updated with data from operating members every ten seconds. These tools enable FRCC security coordinator to implement operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate the line loading and voltage concerns that occur in real time and those identified in the FRCC transmission studies.

FRCC issued one transmission loading relief (TLR) in September 2004 as a result of severe weather associated with Hurricane Frances. The TLR was initiated due to the effects on one of the 500-kV lines within FRCC and concern for the reliability of the region if more transmission were lost. This was the first TLR issued in the region since 1999. Because FRCC is connected to the Eastern Interconnection only along the northern boundary of the state and is electrically unique with its peninsular geography, the occurrence of “thru flows” in the region is almost nonexistent.

The FRCC Operating Reliability Subcommittee developed “lessons learned” from having endured the most active hurricane season in Florida history. This review enabled FRCC to identify and enhance existing preparedness and recovery plans to ensure system reliability for future years.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, they also provide data to FRCC to update and maintain the regional databases. These regional databases are used in the reliability assessment process to ensure the continued reliability of the bulk electric system. FRCC follows a formal reliability assessment process by which it uses a committee and working group structure to annually review and assess reliability issues that either exist or have the potential to develop. This process determines which areas deserve closer scrutiny in the planning and operating studies that will be performed during the year. FRCC members use the results of these studies to ensure that the FRCC region is able to meet the reliability needs of the future. Study results are also provided to the Florida PSC, which has the authority to require installation or repair of generating plants and transmission facilities, if it has reason to believe that inadequacies exist with respect to grid reliability.

In April 2005, FRCC adopted a very comprehensive and in-depth transmission planning process for the FRCC region. This process begins with the annual consolidation of the individual long-term transmission plans of all of the transmission owners in the FRCC region. A detailed analysis of the resulting regional plan will be conducted annually by the FRCC Planning Committee. The assessment will be a robust analysis and will include an examination of multiple expected system conditions and other sensitivities.

The Planning Committee will report its findings, including recommendations for changes or additions to individual transmission owner's plans, to the FRCC Board of Directors for approval. The process also provides for resolution of any identified unresolved issues. The resolution may include the use of an independent evaluator to study and provide input to FRCC. A final report will be sent to the Florida PSC.

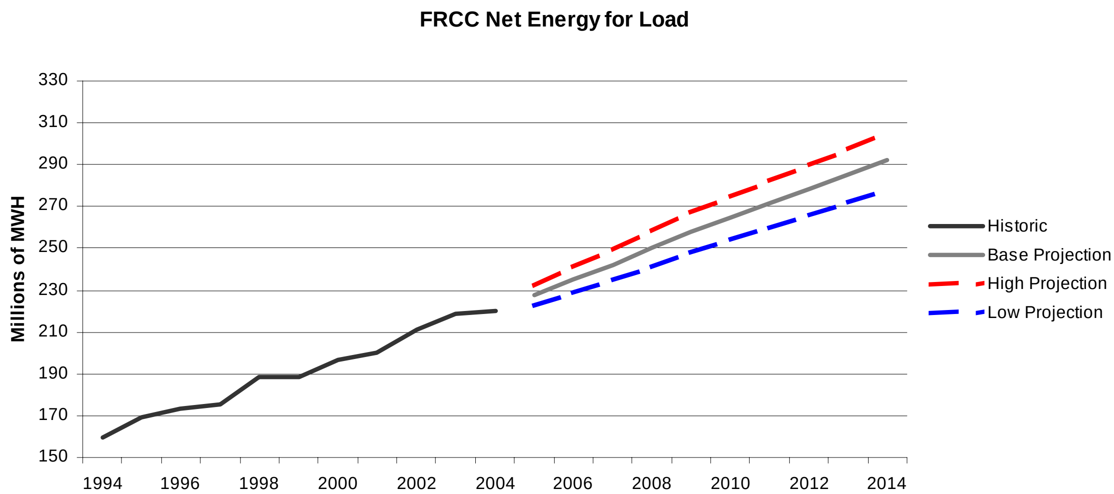
Natural Gas Infrastructure Assessment

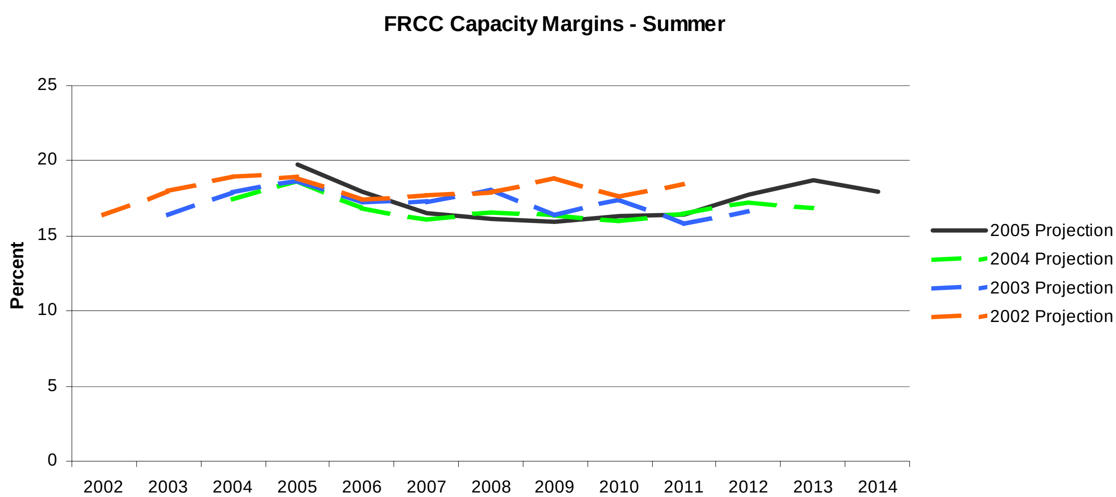
FRCC adopted a high-level methodology to assess its natural gas pipeline and electric interdependency. This methodology was submitted to NERC for informational purposes in 2004. Using this method, FRCC has concluded that it will have adequate natural gas pipeline capacity into the region for the next five years.

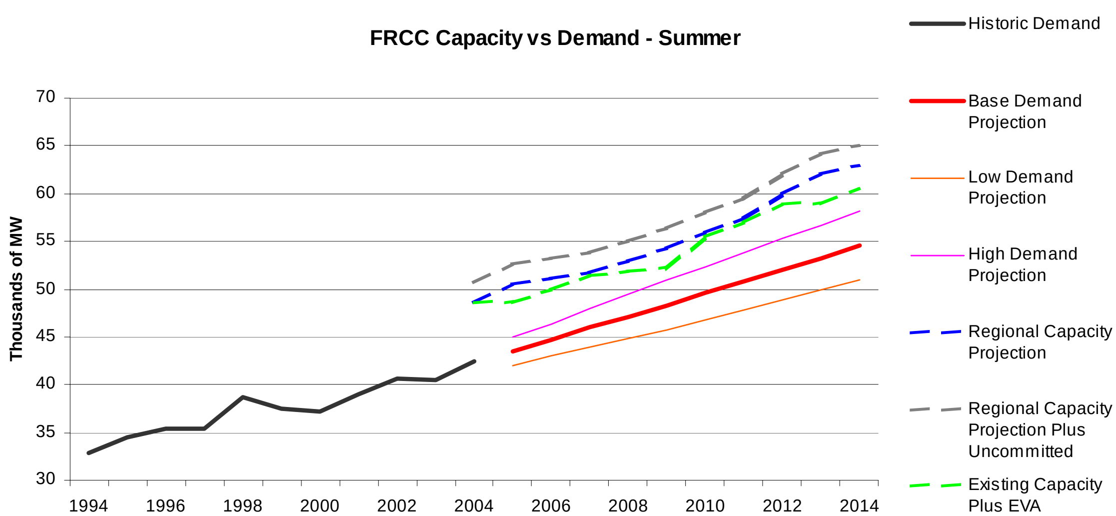
FRCC has already begun work on a more detailed natural gas pipeline and electric interdependency study for the 2006 assessment. FRCC will utilize a transient gas-flow model to study and finitely analyze the gas pipeline system in peninsular Florida. A thorough contingency analysis of the gas pipeline system and the electric generating units burning natural gas will be performed for the 2006 assessment.

FRCC's membership includes 28 members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and IPPs. Historically, the region has been divided into 11 control areas. FRCC now has 25 entities registered as one or more of the following designations: balancing authority, planning authority, reliability coordinator, transmission operator, and transmission planner. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. www.frcc.com

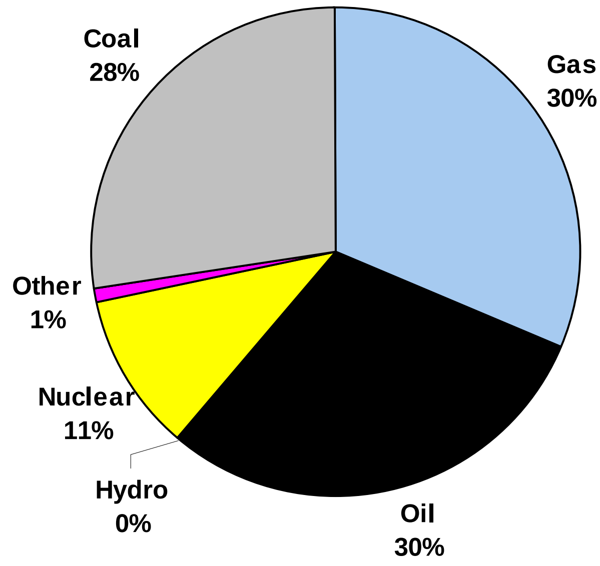
FRCC Capacity and Demand



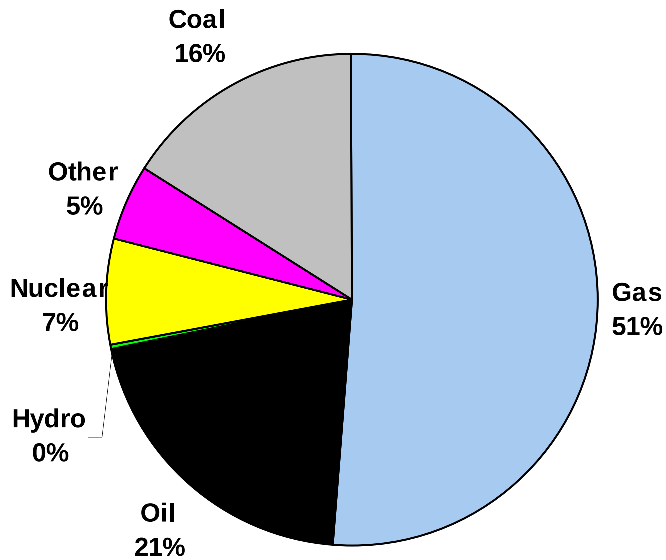




FRCC Capacity Fuel Mix 2000



FRCC Capacity Fuel Mix 2010



MAAC

MAAC is expected to meet forecasted demand and firm obligations throughout the entire assessment period. This is based on MAAC's delegation of administration, operations, and planning functions to PJM and PJM's actions as reliability coordinator, balancing authority, and transmission operator for the entire PJM footprint. PJM's reliability criteria are based on the respective reliability council's criteria, the applicable local planning criteria, an LOLE of one event in ten years, and a transmission deliverability requirement of one event in 25 years. Specifics on LOLE and deliverability are available at www.PJM.com.

MAAC is a summer-peaking region. Generation resources are expected to be adequate and deliverable through 2008. MAAC anticipates that capacity additions will be sufficient to meet the MAAC adequacy objective. This ensures that the LOLE is no greater than one event in ten years.

MAAC is one of the ten regional reliability councils in NERC. Since 1997, PJM has been the NERC reliability coordinator, transmission operator, and balancing authority for the entire PJM footprint, which includes MAAC. While PJM has recently expanded, MAAC has remained essentially the same. New members of PJM with load outside of MAAC are not required to integrate into the MAAC region and have remained a member of their historic reliability councils.

ECAR, MAAC, and MAIN are forming a new large regional reliability council, ReliabilityFirst Corporation, which would combine ECAR, MAAC, and portions of MAIN into a new single council. This new council is scheduled to begin operation on January 1, 2006. The planning and operational policies developed for this new council will supersede the policies and procedures of the existing three councils.

Demand

The summer 2004 total peak demand forecast was 56,886 MW compared with an actual metered value of 52,049 MW (weather adjusted demand of 56,441 MW). The summer 2005 total peak demand forecast is 57,630 MW. The 2005 average total peak demand forecast is 1.7% for the next ten years and has remained consistent with the 2004 forecast. Transmission owner geographic zone growth rates vary from 1.1 to 2.5%.

Resources

Generation resources are expected to be adequate and deliverable through 2008. PJM is currently evaluating generator interconnection requests for more than 18,000 MW of new generating capacity expected by 2010, which is the latest queue position permitted in the regional transmission expansion process (RTEP). While predicting how many generation projects will actually make it on-line is difficult, MAAC anticipates that the above capacity will be sufficient to meet the MAAC adequacy objective. This objective ensures that the LOLE is no greater than one event in ten years.

For the period from 2009 to 2014, additional generation is expected to be constructed to meet reliability needs. Plans are under consideration to further motivate generation developers to locate generation in areas where capacity would be required in the future. The generation considered in the LOLE calculation will be deliverable because developers who plan to install new generation or increase the capacity of existing capacity within PJM must request interconnection, through the RTEP process, with the PJM transmission system and pay for any attachment facilities, local upgrades, and network upgrades necessary to ensure deliverability of the requested generation.

MAAC has a fairly balanced fuel mix with about one third of its capacity fueled by coal, one third fueled by gas, and one third fueled by other sources. PJM participated in the NERC gas interdependency study and will be evaluating gas contingencies, as recommended, in the future.

Energy

The 2004 energy forecast was 279,533 GWh compared with an actual metered value of 282,285 GWh. The 2005 energy forecast is 281,505 GWh. The energy growth rate has increased from 1.5 to 1.7%.

Transmission

Based on identified system enhancements, projected demand growth, and generation in the Transmission Expansion Advisory Committee (TEAC) documentation (available at www.pjm.com), transmission capability over the next five years is expected to meet the applicable reliability area criteria within the PJM footprint. Transmission upgrades in the northern New Jersey area for the years 2008–2010 are still under evaluation to accommodate generator retirements and maintain transmission system reliability within the applicable criteria.

For the period of 2009 to 2014, MAAC expects additional generation to be constructed to meet reliability needs because of additional incentives under consideration for generation developers to locate generation in areas where capacity is required. Transmission expansion is another way to get capacity to the needed areas to meet the MAAC reliability requirements but transmission expansion would take more time and effort to install.

PJM evaluates all proposed independent merchant transmission projects under the RTEP queue process to assure firm or nonfirm withdrawal or injection rights. However, firm withdrawal rights without firm capacity and firm point-to-point transmission service in PJM does not place any obligations on MAAC to supply any energy.

MAAC validates the reliability studies of the MAAC portion of the PJM footprint as well as performing many specialized planning studies as needed within the RTO and with surrounding systems. The operating reliability impact of interactions with neighboring regions is assessed by participation in MEN and VEM interregional reliability assessments.

The Neptune Regional Transmission System, LLC merchant transmission interconnection project consists of one HVDC connection from PJM to New York. The connection originates near the Sayreville 230-kV substation in PJM and will terminate at the Newbridge Road 138-kV substation on Long Island, New York. Capability will be 790 MW and the developer has requested firm transmission withdrawal rights in the amount of 685 MW and nonfirm transmission withdrawal rights in the amount of 105 MW at the HVDC terminal in PJM. The HVDC terminal will be located in Sayreville, New Jersey, in the vicinity of the Sayreville (a.k.a. Raritan River) 230-kV substation. Neptune is scheduled for commercial operation in 2007.

Operations

PJM forecasts, schedules, and coordinates the operation of generating units and 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 the transmission lines in the MAAC region. Operations are closely coordinated with neighboring reliability coordinators, balancing authorities, and transmission operators. Additionally, information is exchanged to enable real-time security assessments of the transmission grid.

MAAC has a fairly balanced fuel mix with approximately one third of its capacity fueled by coal, one third fueled by gas, and one third fueled by other sources. PJM participated in the NERC Gas Interdependency Study and will be evaluating gas contingencies, as recommended, in the future.

To mitigate congestion and other reliability concerns at the interface between PJM and MISO, a joint MISO-PJM operating agreement is in place. The agreement identifies the transmission rights and obligations of MISO in the PJM footprint and the transmission rights and obligations of PJM in the MISO footprint. Further, each RTO has the ability to request that generation be operated in the other RTO to preserve transmission rights and to relieve congestion in its footprint.

No operating issues have been identified for the PJM footprint in the assessment period.

Assessment Process

Since 1997, PJM has been the NERC reliability coordinator, transmission operator, and balancing authority for the entire PJM footprint, which includes MAAC. While PJM has expanded, MAAC has remained essentially the same. This expansion now includes the transmission systems in all or part of Pennsylvania, New Jersey, Maryland, Ohio, Kentucky, Delaware, Virginia, West Virginia, Illinois, North Carolina, and the District of Columbia. New members of PJM with load outside of MAAC are not required to integrate into the MAAC region and have remained in their historic reliability councils.

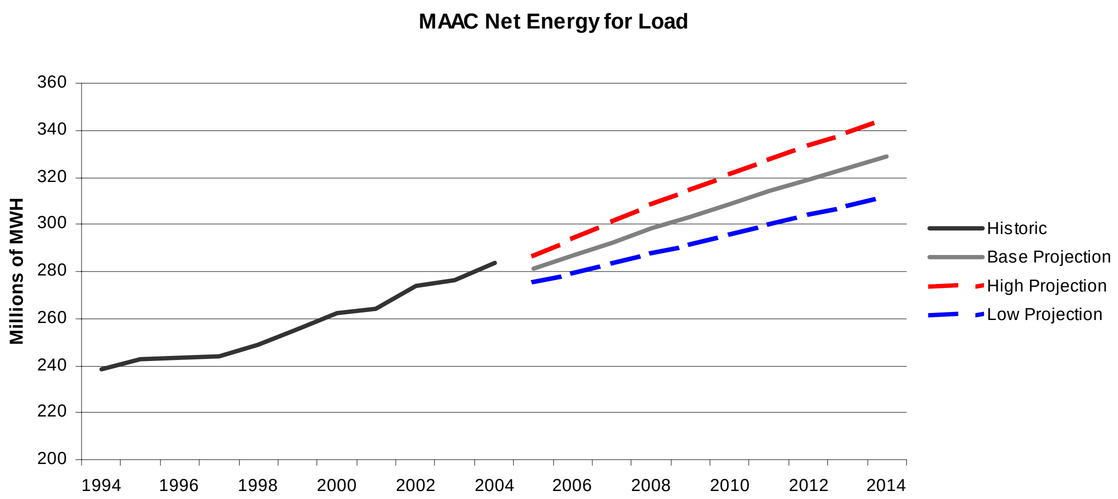
This footprint of PJM is operated and planned employing one security-constrained economic dispatch protocol using the applicable criteria of the respective region, local criteria, the PJM deliverability requirements, and PJM market rules. The operation and planning of the total PJM footprint provides reliability. Operational analyses of subareas, such as MAAC, are misleading and inappropriate.

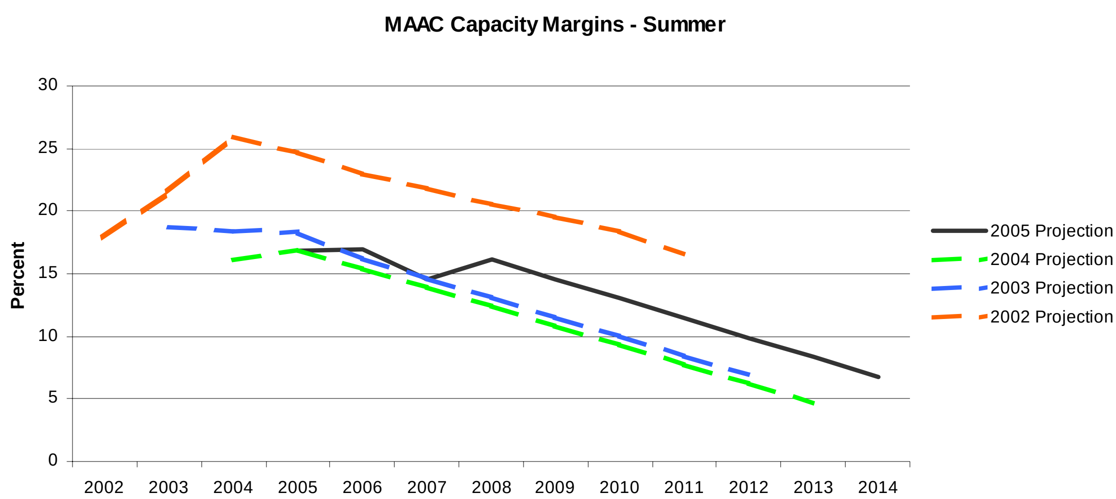
The planning process has been expanded to include reliability, economic, and operational performance projects. The reliability projects are based on meeting reliability criteria, while the economic projects are based on a cost-benefit analysis, which considers congestion costs and takes into account various financial hedging instruments. Operational performance projects are related to events that are observed by the PJM operators, but were not predicted in the planning studies.

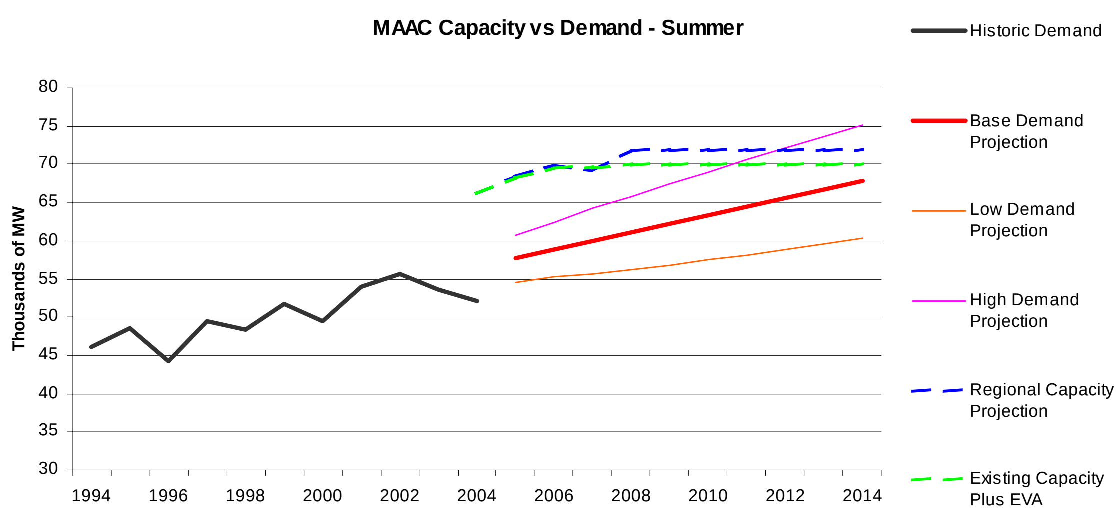
The market rules include a capacity market and the use of a locational marginal pricing mechanism to make congestion transparent. Making congestion transparent through locational marginal pricing provides a market mechanism to allow for mitigation of congestion. A reserve requirement is presently set for a planning period two years into the future so that the market can provide sufficient adequacy or for the load-serving entities to construct generation. A future reserve construct, which values the quantity, quality, and location of generation, is presently going through the stakeholder process.

MAAC serves more than 22 million people in a nearly 50,000 square mile area in the Mid-Atlantic region. The region includes all of New Jersey, Delaware, the District of Columbia, major portions of Pennsylvania, Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves 8% of the electrical demand. As of May 2005, PJM and MAAC had 359 members. MAAC operates under an agreement that became effective January 1, 2001, which combined PJM and MAAC membership and is available for review on the MAAC Web site at www.maac-rc.org.

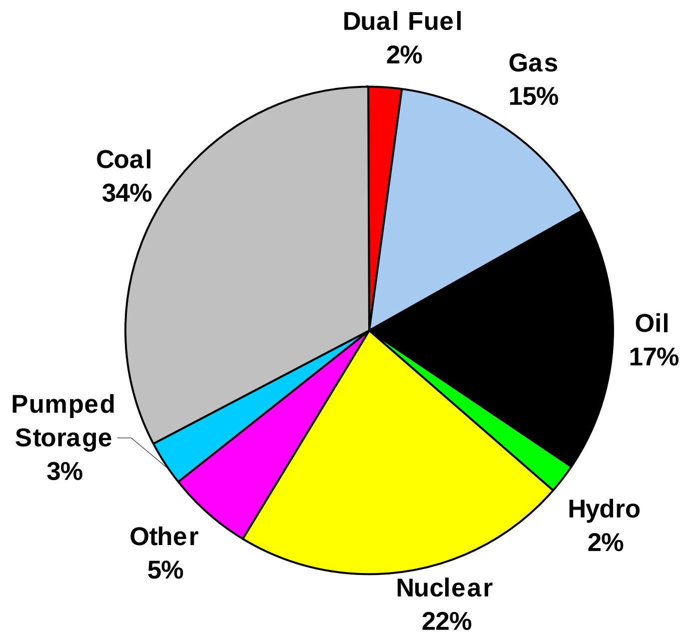
MAAC Capacity and Demand



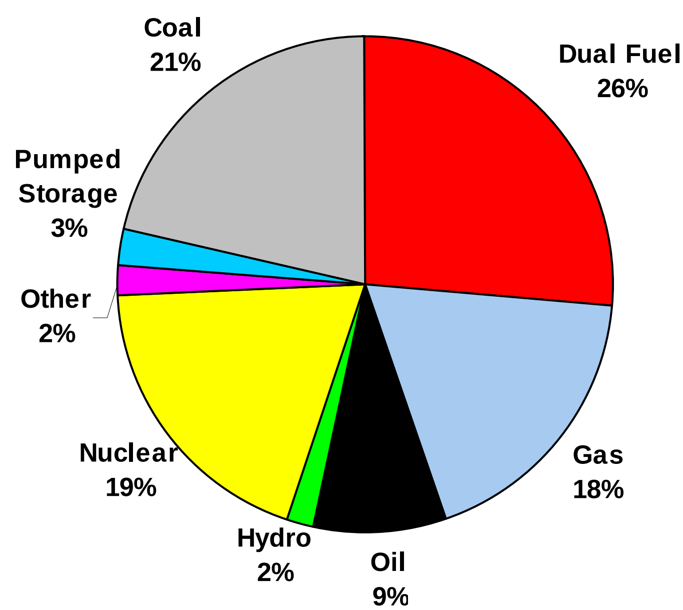




MAAC Capacity Fuel Mix 2000



MAAC Capacity Fuel Mix 2010



MAIN

Within MAIN, generation resources are expected to be adequate through 2012 based on current forecasts, and MAIN's recommended long-term planning reserve margin of 16 to 19%. By 2014, the planning reserve margin for MAIN is projected to decrease to 12%.

For the planning horizon, MAIN expects its transmission system to perform adequately assuming proposed reinforcements are completed on schedule. However, operational challenges will exist on the Minnesota-to-Wisconsin interface prior to completion of the Arrowhead-Gardner Park (Weston) 345-kV reinforcement project. This reinforcement is expected to be in service by mid-2008 and will help to alleviate thermal, voltage, and stability limitations along the interface.

In response to the recommendations contained in U.S.-Canada task force report on the August 2003 blackout, MAIN is continuing to pursue implementation of the recommendations that apply to MAIN.

ECAR, MAAC, and MAIN are working toward the formation of a large regional reliability council, ReliabilityFirst Corporation, which would combine ECAR, MAAC, and portions of MAIN into a single council. The large regional reliability council is tentatively scheduled to begin day-one operations by January 1, 2006. The planning and operational policies and procedures for the large regional reliability council will supersede the policies and procedures of the existing three regions. Some MAIN members may decide to join the MRO instead.

Demand

MAIN projects its total internal summer peak demand to increase from 59,154 MW in 2005 to about 68,600 MW in 2014. This is an average annual growth rate of 1.8%, which is slightly higher than last year's forecasted average annual growth rate of 1.5%. As in the past, this year's projections are based on the assumption of average weather conditions and the current forecast of economic growth. The actual 2004 peak demand in MAIN was 53,439 MW, which was lower than projected due to substantially cooler than normal temperatures during the 2004 summer.

Long-term sales to other regions, where the purchasing entities are known, are forecasted to increase from about 1,400 MW in 2005 to 1,500 MW in 2014. Long-term purchases from other regions, where the selling entities are known, are projected to decrease from their current level of about 1,600 MW to 1,100 MW in 2014 as contracts expire.

Based on information from MAIN members, purchases and sales where the buyer or seller is unknown are projected to increase from a net purchase of about 200 MW in 2005 to a net purchase of about 2,900 MW in 2014.

Resources

About 5,600 MW of additional capacity resources are projected to be in service within the MAIN region by 2014. About 950 MW, or 17%, of these projected capacity resources are combustion turbines and combined-cycle plants. Last year, MAIN projected about 9,900 MW of additional capacity resources in the MAIN region by 2014, with about 5,700 MW, or 58%, of these projected capacity resources being combustion turbines and combined-cycle plants. The magnitude of the variation in additional capacity resources from last year to this year reflects the uncertainty faced by the region in assessing long-term resource adequacy.

Based on this year's forecast of demand and capacity, and excluding purchases where the seller is unknown, the long-term planning reserve margins for MAIN as a whole are expected to be within or above the MAIN recommended reserve margin range of 16 to 19% through 2012. MAIN as a whole is expected to meet its criterion of one-day-in-ten-years LOLE through 2012. By 2014, the reserve margin for MAIN as a whole is projected to decline to 12%, or about 2,500 MW below the current MAIN recommended reserve margin range. MAIN does not believe this is a significant issue, because sufficient time remains for additional capacity to be planned and installed in the region during the next ten-year period. This is based on the projected reserve margins for MAIN calculated in accordance with MAIN Guide 6.

MAIN's present capacity is 67,847 MW with a mix of 41% coal, 21% nuclear, 33% gas, and 5% other. MAIN's capacity in 2014 is projected to be about 78,000 MW, with a projected mix of 45% coal, 20% nuclear, 30% gas, and 5% other.

None of MAIN's members expect any fuel supply or delivery problems during the assessment period although concern remains over the potential of a single-mode natural gas pipeline failure to affect multiple plants.

Energy

MAIN projects its electrical energy usage to increase from 286,000 GWh in 2005 to about 329,000 GWh in 2014. This is an annual increase of 1.6%, which is slightly higher than last year's forecasted average annual growth rate of 1.4%. As in the past, this year's projections are based on the assumption of average weather conditions and an updated forecast of economic growth. The actual 2004 electrical energy usage in MAIN was 274,760 GWh.

Transmission

For the planning horizon, MAIN expects its transmission system to perform adequately if planned reinforcements or some equivalent of these plans are installed. This assessment is based on historic and current analyses used to judge compliance with NERC reliability standards TPL-001 through TPL-004.

The following major reinforcement plans relate to compliance with the reliability standards and other reasons (aging facilities, in-house criteria, demand growth, IPP connections, and parallel path flow concerns).

- 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.
- Callaway-Franks 345-kV line, Baldwin-Rush Island 345-kV line, and Loose Creek-Jefferson City 345-kV supply line related to new 345/161-kV substation in South MAIN.
- Arrowhead-Gardner Park 345-kV line, conversion of the Columbia-North Madison 138-kV line to 345-kV, Rockdale (future Verona)-West Middleton 345-kV line, Gardner Park-Central Wisconsin 345-kV line, Morgan-Werner West 345-kV line, Rockdale-Jefferson-Concord rebuild 138-kV line to double circuit 345/138-kV line, Concord-Bark River 345-kV line and conversion of the Bark River-Lannon 138-kV line to a 345-kV line in Wisconsin-Upper Michigan Systems (WUMS).
- Crawford-West Loop-Taylor 345-kV lines and up-grade Burnham-Taylor 345-kV lines in northern Illinois.

These plans improve the adequacy of MAIN's transmission system. In-service dates for each facility listed are found in MISO's transmission expansion plan, located on the MISO Web page (www.midwestiso.org) at http://www.midwestiso.org/plan_inter/expansion.shtml.

Delays in getting regulatory approval and permits and in acquiring rights-of-ways could influence future reliability assessments and may require implementation of other alternatives including operating measures. Development of MISO RTO processes and their impact on the overall planning activities, coordination of transmission service roll-over-rights, and implementation of other market rules (MISO Day 2) offer further challenges. Coordination of these factors, including seams issues between RTOs and neighboring entities, will help to ensure future reliability.

In response to the U.S.-Canada task force report on the August 2003 blackout, MAIN is continuing to pursue several activities including additional voltage analysis using NERC category C and D contingencies in near-term and future system studies, and is participating in the NERC summer readiness audits.

Operations

MAIN functions as a reserve-sharing group (RSG) with balancing authorities sharing reserves in order for the RSG to comply with the NERC disturbance control standard. The MAIN callable reserve system continues to reliably facilitate implementation of the RSG process.

The addition of pollution control equipment for NO_x reduction causes an increase in auxiliary power use and may result in reductions in net unit capabilities. Possible CO_2 reduction requirements could have significant impacts on fossil fuel generation, especially coal-fired units.

Assessment Process

MAIN transmission owners/providers provided assessments for their systems. Specifically, MAIN transmission owners assessed 2006 summer, 2006/2007 winter, and 2014 summer conditions as requested by MAIN; some owners also included assessments of other time periods and in-house studies.

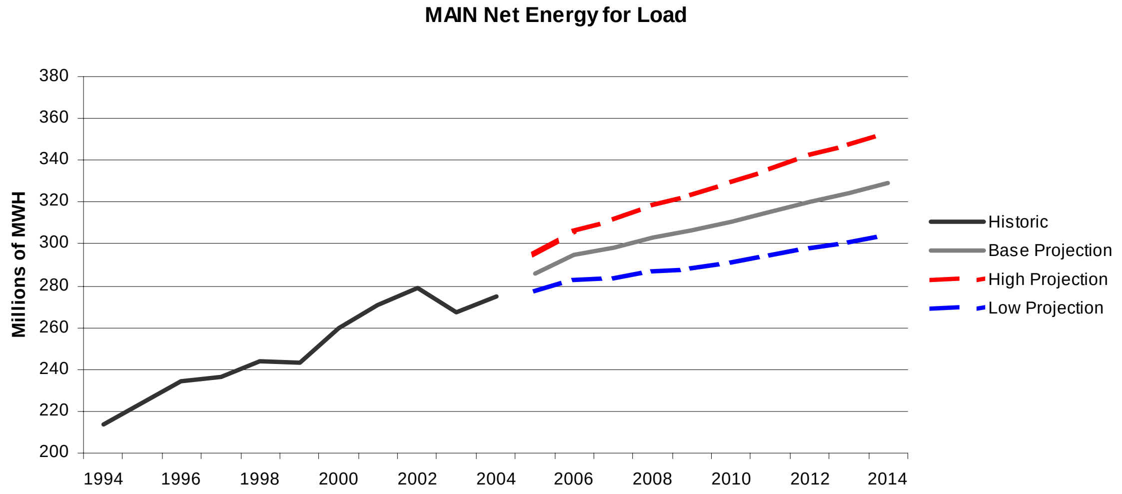
MAIN made its assessment using the following studies:

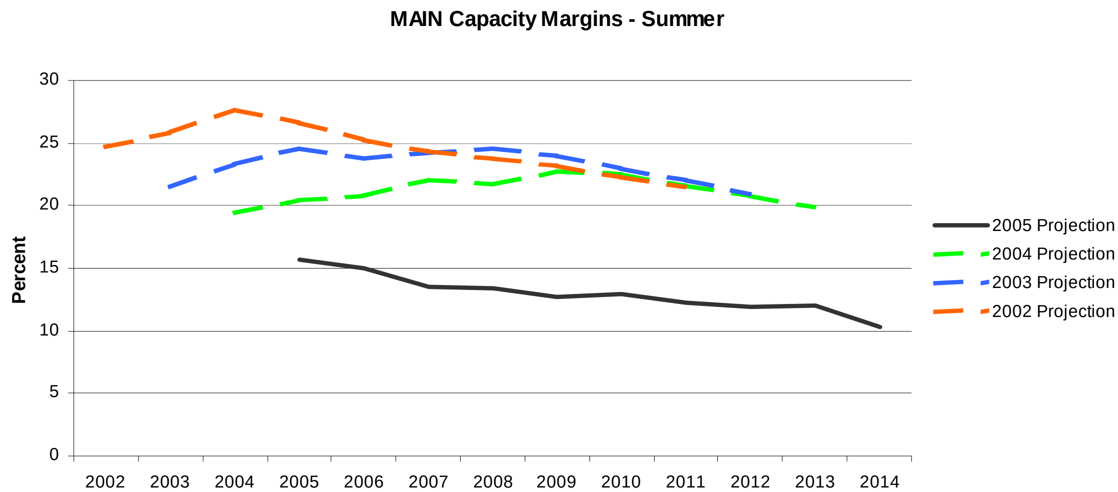
1. Assessments from in-house studies provided by MAIN transmission owners;
2. 2009 dynamic stability based on 2014 summer screening; and
3. The MAIN Future System Study Group (FSSG) studies done in previous years.

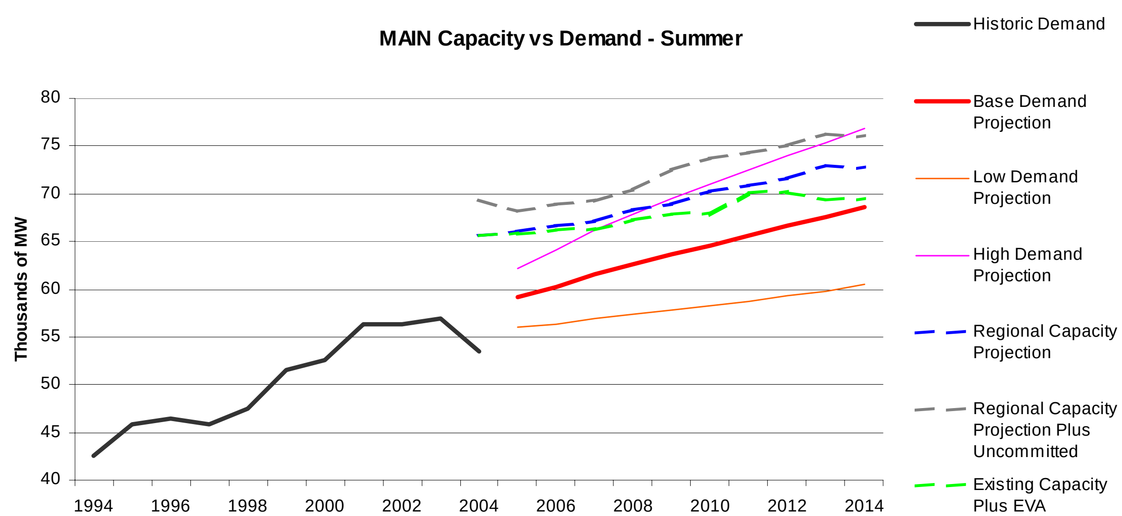
The assessment was more specific for the near-term period than for the longer-term period, as there are more uncertainties involved in longer-term simulations. Some category C study results indicate potential local area problems but those problems are adequately mitigated with operator intervention. Also in the future, regional reliability organization (RRO) and RTO coordinated planning activities are expected to provide enhanced assessments of the longer-term planning horizon.

The 27 members and two associate members of MAIN include 13 balancing authorities, part of one additional balancing authority, and other organizations involved in regional energy markets. MAIN is a summer-peaking region serving a population of about 21 million in a geographic area of about 145,000 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.

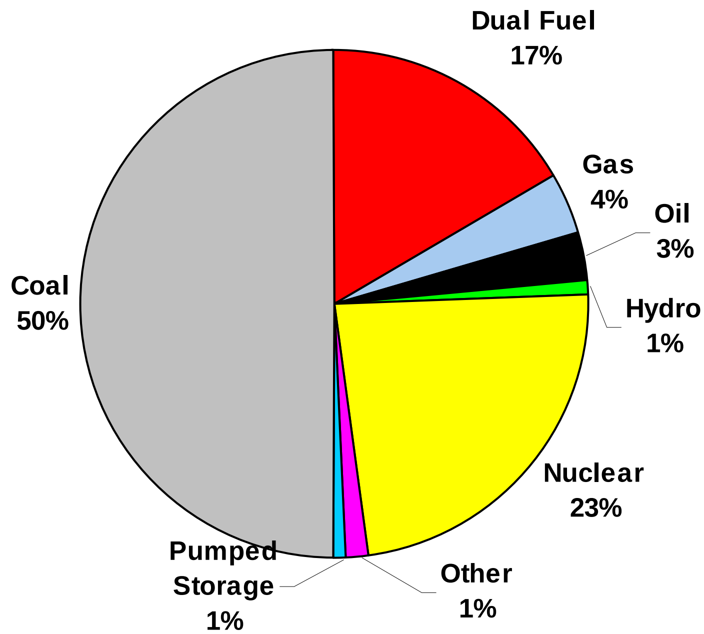
MAIN Capacity and Demand



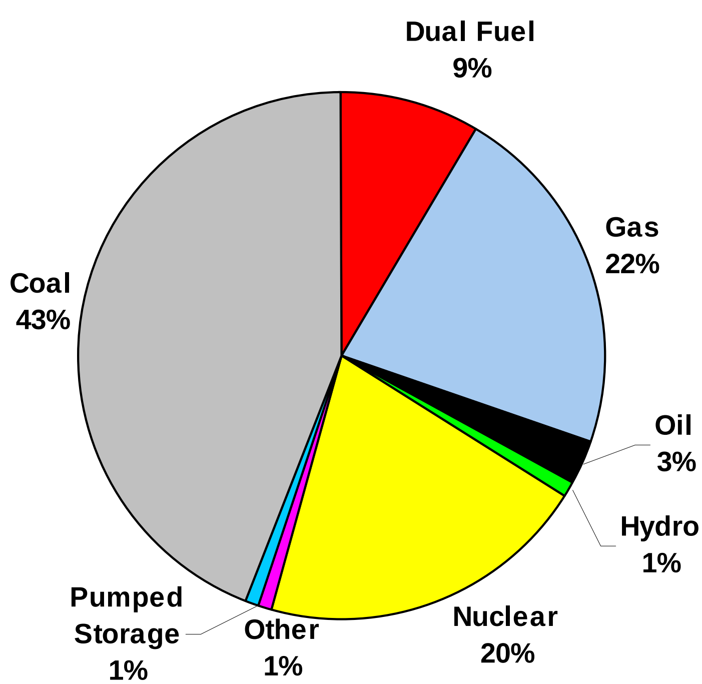




MAIN Capacity Fuel Mix 2000



MAIN Capacity Fuel Mix 2010



MRO

In January 2005, the MRO replaced the Mid-Continent Area Power Pool (MAPP) as the NERC regional reliability council. MAPP functions were streamlined to include the MAPP Generation Reserve Sharing Pool and MAPP Regional Transmission Committee, which remain operational. Although the MRO membership plans to expand its geography later in 2005 and 2006, the 2005 assessment is more reflective of the former MAPP region.

The MRO plans to have sufficient generating capacity to meet its reserve capacity obligations through 2010. While the Canadian region of the MRO, MRO-Canada, has adequate generating capability throughout the assessment period, currently planned capacity reported in the U.S. region of the MRO, MRO-U.S., is below MRO requirements for reserve capacity obligations from 2011 to 2014. The MRO, however, does not expect any capacity deficits to occur anytime during the assessment period of 2005–2014, because the MRO has mechanisms in place to ensure that capacity requirements are met.

The MRO transmission systems are adequate to meet the committed needs of the member systems and will continue to meet reliability criteria throughout the period. The MRO expects the system to be heavily used due to continuing power marketing activity, and in order to operate reliability, may not be able to meet all market needs.

Demand

The MRO-U.S. 2005 noncoincident summer peak demand is projected to be 30,134 MW. This projection is 2.7% above the 2004 noncoincident summer peak demand (29,351 MW). The MRO-U.S. summer peak demand is expected to increase at an average rate of 2.0% per year during the 2005–2014 assessment period, compared with 1.7% predicted last year for the 2004–2013 period. The MRO-U.S. 2014 noncoincident summer peak demand is projected to be 35,612 MW. This projection is 1.9% above the 2013 noncoincident summer peak demand predicted last year (34,965 MW).

The MRO-Canada 2005 noncoincident summer peak demand is projected to be 5,761 MW. This projection is 3.1% above the 2004 noncoincident summer peak demand (5,589 MW). The MRO-Canada summer peak demand is expected to increase at an average rate of 1.17% per year during the 2005–2014 assessment period, compared with 1.29% predicted last year for the 2004–2013 period. The MRO-Canada 2014 noncoincident summer peak demand is projected to be 6,367 MW. This projection is 1.13% above the 2013 noncoincident summer peak demand predicted last year (6,296 MW).

The MRO-Canada 2005 noncoincident winter peak demand is projected to be 7,024 MW. This projection is 0.3% above the 2004 noncoincident winter peak demand (7,004 MW). The MRO-Canada winter peak demand is expected to increase at an average rate of 0.8% per year during the 2005–2014 assessment period, compared with 1.2% predicted last year for the 2004–2013 period. The MRO-Canada 2014 noncoincident winter peak demand is projected to be 7,521 MW. This projection is 0.8% above the 2013 noncoincident winter peak demand predicted last year (7,458 MW).

Long-term sales to other regions where the purchasing entities are known are expected to decrease from their current level of 645 MW in 2004 to about 240 MW in 2014. Long-term purchases from other regions where the selling entities are known are expected to decrease from their current level of 923 MW in 2004 to about 70 MW in 2014. Based on information from MRO members, there will be no purchases or sales where the buyer or seller is unknown reported from 2005 to 2014.

MRO members continue to forecast demand based on normal weather conditions.

Resources

Generating resources for MRO-Canada are forecast to be adequate over the ten-year assessment period. Current planned capacity reported in the MRO-U.S. region is below MRO requirements for reserve capacity obligation during 2011–2014. For the purpose of this assessment, the MRO utilizes the MAPP restated agreement, which obligates the member systems to maintain reserve margins at or above 15%, which is the same as a 13.0% minimum capacity margin requirement. The summer reserve margin is forecast to decline from a high of 18.0% in 2005 to 11.2% in 2011 and 6.7% in 2014. These figures include an additional 2,122 MW of new generation for the period of 2005 to 2014 as reported to NERC in the *EIA-411 Report*.

Although planned capacity reported in the MRO-U.S. region is below requirements for reserve capacity obligation during 2011 to 2014, MRO believes that no capacity deficit will occur anytime during the next ten-year period. For this assessment, the MRO members belong to the MAPP Reserve Sharing Pool, which has requirements for reserve capacity obligation with financial penalty and continually monitors the members' reserve margins. This mechanism, or some future MRO capacity arrangements, would ensure that the members plan for adequate capacity to meet their expected demand.

No known fuel limitations are anticipated in the region.

Energy

The MRO tracks annual electricity use by both region and subregion:

- Annual electricity usage for the entire MRO region in 2004 (195,528 GWh) was 0.6% above 2003 consumption (194,286 GWh) and 3.0% below the 2004 forecast (201,605 GWh).
- Annual electricity usage for MRO-U.S. in 2004 (154,053 GWh) was 1.1% above 2003 consumption (152,310 GWh) and 3.7% below the 2004 forecast (159,932 GWh).
- Annual electricity usage for MRO-Canada in 2004 (41,475 GWh) was 2.7% above 2003 consumption (40,369 GWh) and 0.5% below the 2004 forecast (41,673 GWh).

Transmission

The existing transmission system within MRO-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. The 2004 regional plan showed that the MRO-U.S. members planned to add 695 miles of 345-kV and 111 miles of 230-kV transmission lines in the 2004–2013 time frame.[9] The MRO-Canada existing transmission system is comprised of 4,578 miles of 230-kV and 130 miles of 500-kV transmission lines. MRO-U.S. and MRO-Canada have a total of 2,030 miles of HVDC lines. MRO-Canada is planning for 500 miles of additional 230-kV transmissions in the 2004–2013 time frame.

MRO 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 designated subcommittees of the MAPP Regional Transmission Committee (RTC). 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, prepared the MAPP 2004 regional plan to address the needs of all stakeholders. In addition to the transmission planning process conducted through the RTC, those MRO transmission owners within MISO are participating in the MISO transmission expansion planning process.

[9] The 2005 regional plan covering 2005–2014 has not yet been issued.

In general, the MRO 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. MRO continues to monitor the 31 limiting flowgates within the region.

System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO 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. This line is expected to be in service in 2008.

The Transmission Planning Subcommittee of the RTC determined a simultaneous import limit for the 2009 base case as a part of the *MAPP 2004 Ten-Year Regional Plan*. This study indicated that, during summer peak demand conditions when imports are expected to be maximized, a simultaneous import transfer limit of about 1,800 MW exists. This equates to about 5.1% of the 2004 forecast peak demand of 35,335 MW. Imports gradually increase to about 3,600 MW as demand decreases to about 80% of the forecast load.

Operations

MRO 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 to coordinate transmission system maintenance. The MAPP Generation Reserve Sharing Pool (GRSP) continues to provide a benefit to the region through the sharing of generation reserves during system emergencies.

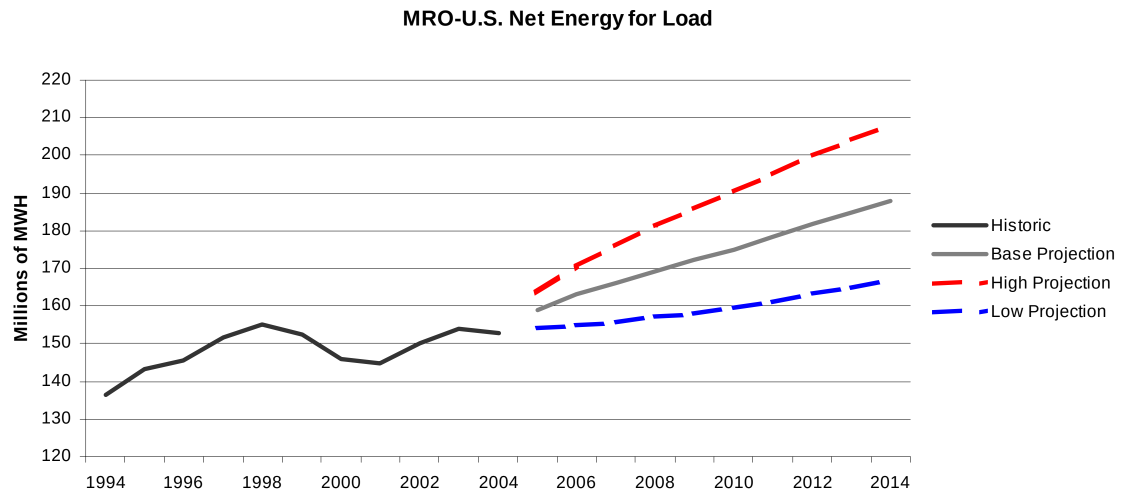
The MISO energy market commenced on April 1, 2005. The market covers transactions in portions of ECAR, MAIN, and MRO across 15 states. MAPP (RTC and GRSP) and MISO continue to discuss issues related to implementing the seams operating agreement to coordinate transmission service on reciprocally managed flowgates and congestion management including TLR avoidance procedures.

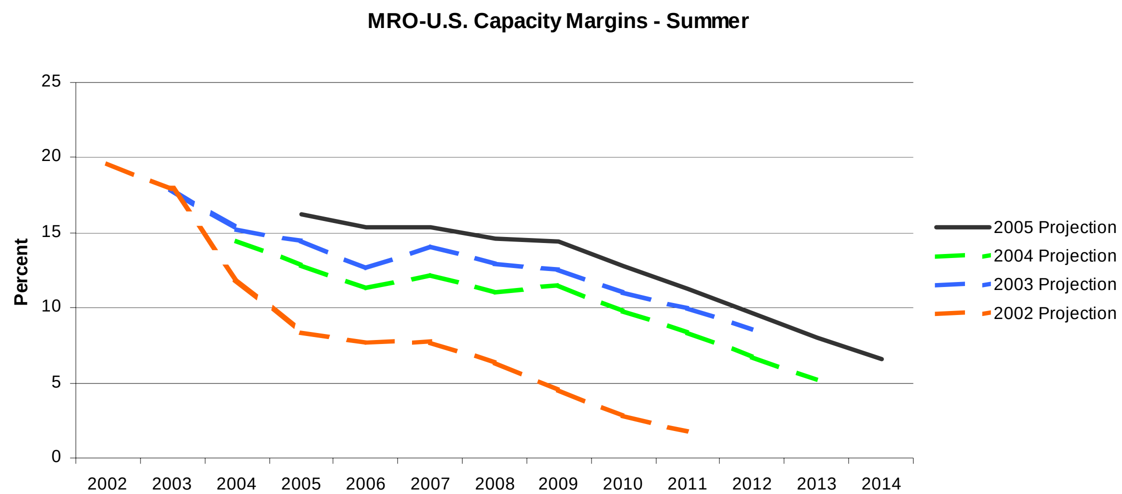
Assessment Process

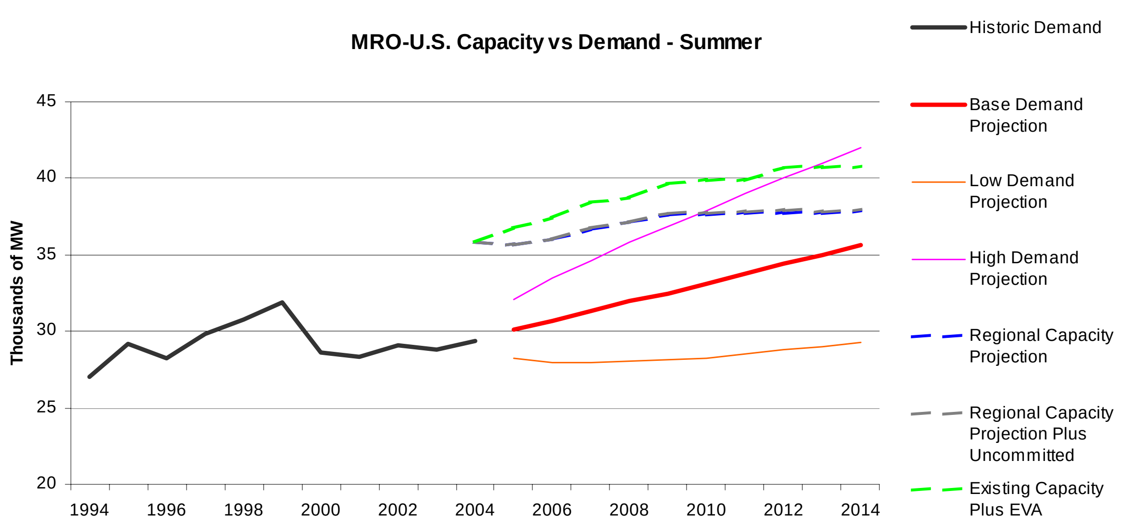
The MRO Reliability Assessment Committee is responsible for the long-term reliability assessment. The Transmission Reliability Assessment and Composite System Reliability Working Groups jointly prepare the MRO ten-year reliability assessment. The Reliability Studies, Design Review, and Transmission Operations Subcommittees review MRO reliability from near-term and long-term perspectives.

The MRO membership now totals 41 members, which includes members that could be designated as either a cooperative, Canadian utility, federal power marketing agency, generator and/or power marketer, small investor-owned utility, large investor-owned utility, municipal utility, regulatory participant, and transmission system operator. The MRO region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is about 1,000,000 square miles with an estimated population of 20 million.

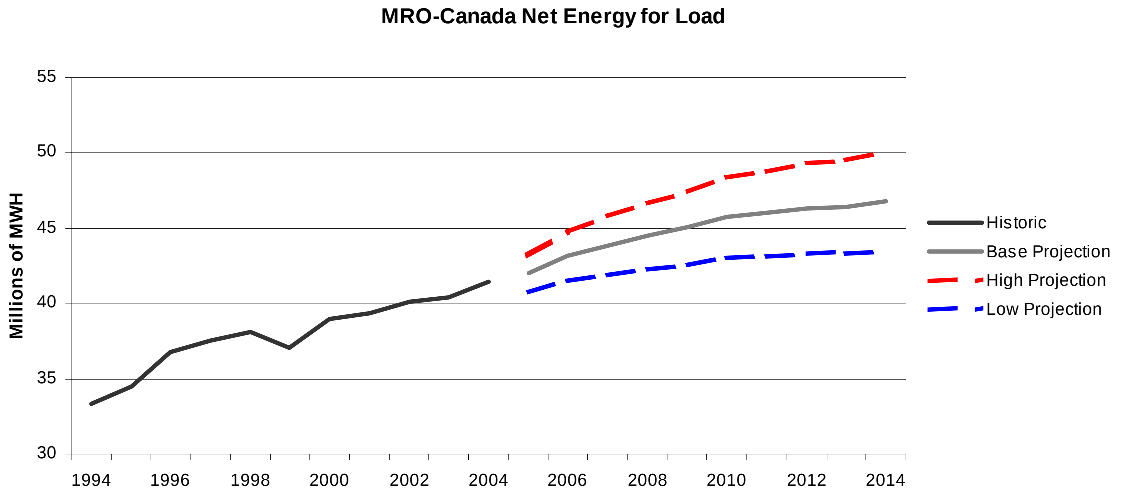
MRO-U.S. Capacity and Demand

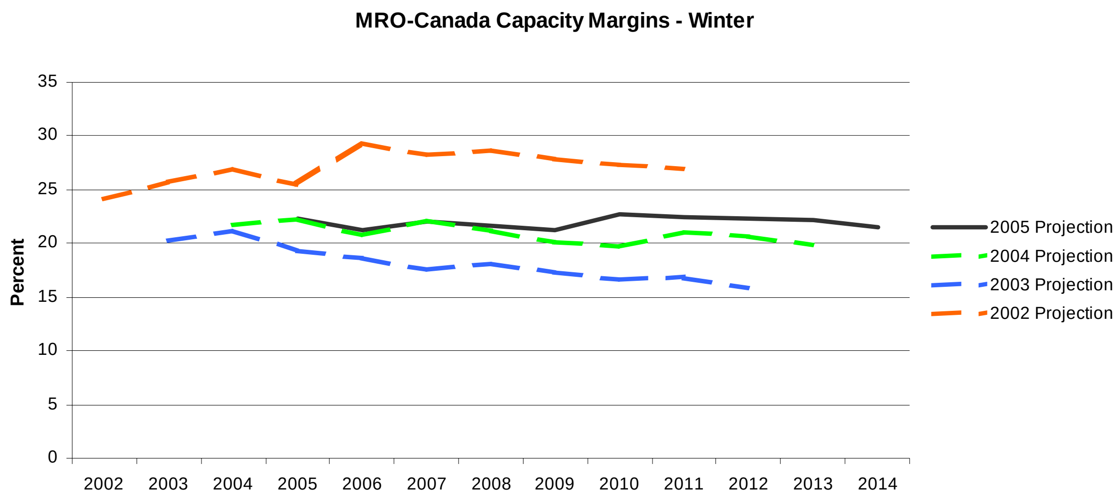


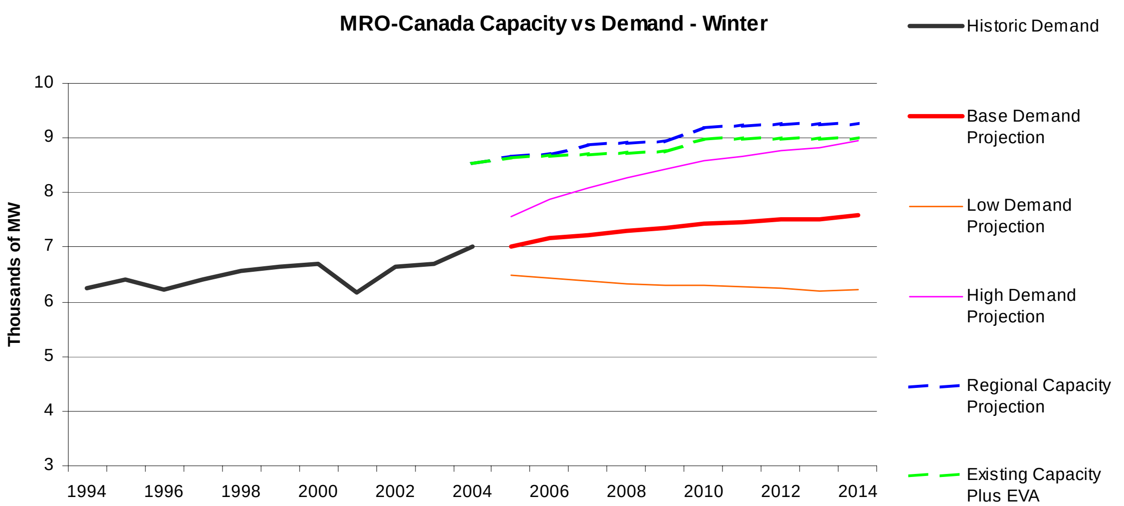




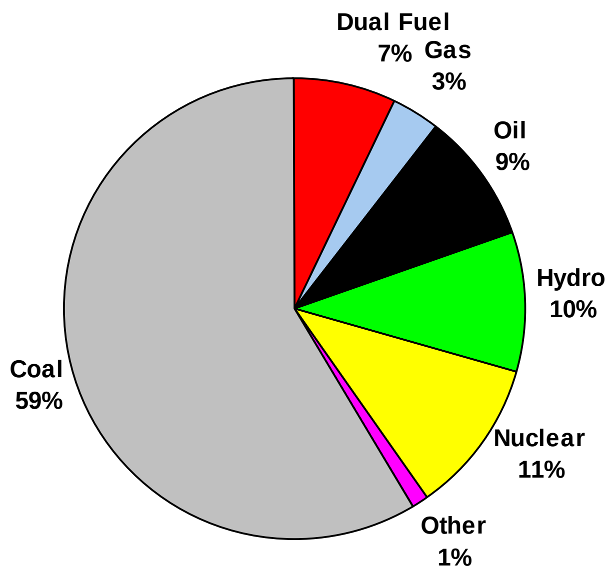
MRO-Canada Capacity and Demand



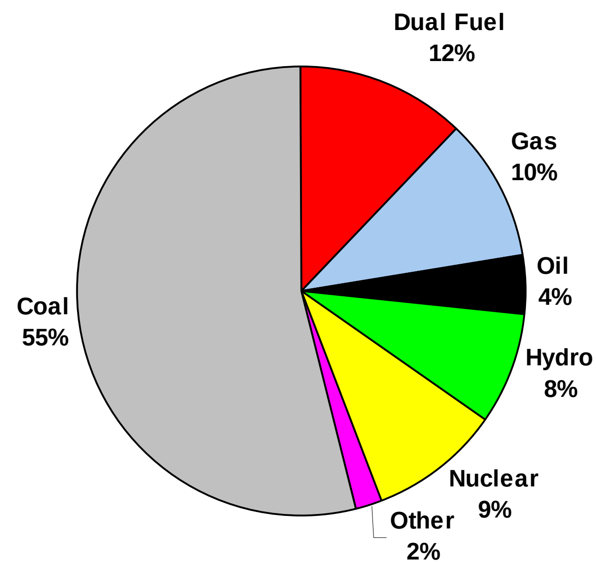




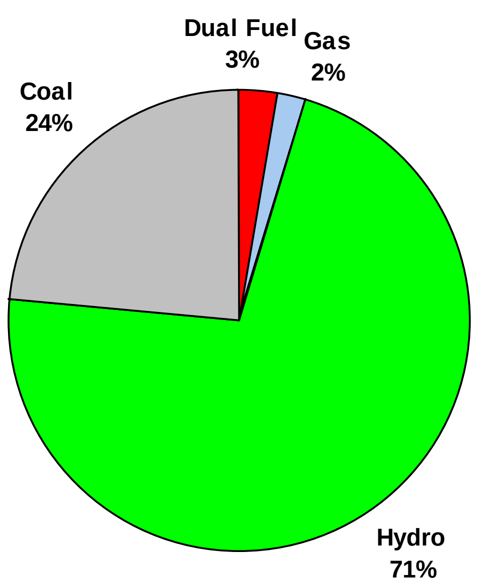
MRO-U.S. Capacity Fuel Mix 2000



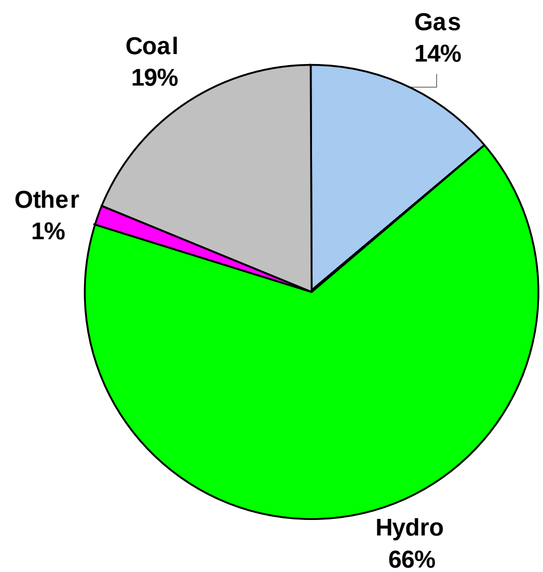
MRO-U.S. Capacity Fuel Mix 2010



MRO-Canada Capacity Fuel Mix 2000



MRO-Canada Capacity Fuel Mix 2010



NPCC

Recognizing its diversity, the adequacy of the NPCC is measured by assessing the five subregions of NPCC: the Maritimes (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd., and the Northern Maine Independent System Administrator, Inc), New England (ISO-NE), New York (the New York Independent System Operator (ISO)), Ontario (IESO), and Québec (Hydro-Québec TransÉnergie). In the latter five years of the assessment period, additional resources must continue to be secured by Ontario, New England, and New York to maintain compliance with the NPCC resource adequacy criterion.

Among the five NPCC areas, the Maritimes and Québec are predominantly winter-peaking systems. Ontario has historically experienced its annual peak demand in the winter. However, in three of the last five years, Ontario's annual peak demand occurred during the summer due to extreme weather conditions. Based on normal weather conditions, Ontario is forecast to become a summer-peaking area in 2007, and the New York and New England areas continue to be summer-peaking systems. Consequently, the mix of winter and summer peaking areas could make an NPCC-wide comparison of year-to-year peaks misleading.

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.*[10] This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for the five NPCC areas: the Maritimes, New England, New York, Ontario, and Québec. 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.*[11] The area must successfully demonstrate the following:

- 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 the resource criteria meet the NPCC Document A-02 criterion[11] 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 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 of one area 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 one or more other NPCC areas. If, in the course of the study, such problems of an inter-area nature are found, NPCC informs the affected systems and areas, works

[10] http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/b-08.pdf
[11] http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf

with the area to develop mechanisms to mitigate potential reliability impacts and monitors the resolution of the concern.

Subregions

Maritimes

The Maritimes is a winter-peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NSPI), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc. (NMISA). MECL supplies the province of Prince Edward Island.

On October 1, 2004, New Brunswick's Electricity Act restructured the electric utility industry in New Brunswick and created the NBSO. The NBSO is an independent not-for-profit statutory corporation separate from the NB Power group of companies. The Electricity Act transferred the responsibility for the security and reliability of the integrated electricity system from NB Power to NBSO, and also made NBSO responsible for facilitating the development and operation of the New Brunswick electricity market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the open access transmission tariff (OATT) and the market rules.

Demand — Separate demand and energy forecasts are prepared individually by each of the Maritimes area jurisdictions, as no regulations require a single authority to produce a forecast for the Maritimes as a whole. Demand forecasts developed by the NBSO, NSPI, MECL, and the NMISA incorporate such factors as climate history, economic indicators (including projected energy costs), technological factors, and demographic changes. To conduct area studies, the individual forecasts are combined by using the load shape of each jurisdiction to arrive at a composite value for the Maritimes. The composite peak demand forecast for the Maritimes for 2006 is 5,585 MW, 53 MW (0.9%) less than that forecast last year. The only firm long-term sales contract to another area is a 200 MW firm capacity sale to Hydro-Québec from New Brunswick, in place until March 31, 2011.

Resources — The NPCC *Maritimes Area Triennial Review of Resource Adequacy*[12] determined that the Maritimes' adherence to a 20% reserve criterion complies with the NPCC resource adequacy criterion of 0.1 days per year LOLE. The current projected annual capacity margins for the Maritimes meet the 20% reserve criterion in all years except for the 2008/2009 winter period, which has a forecast capacity deficit in the Maritimes of 240 MW. This is largely due to the planned refurbishment of the 635-MW Point Lepreau nuclear generating station. As the project is still awaiting the approval of the New Brunswick provincial government, plans have not yet been identified for replacement capacity during the refurbishment period.

Generation capacity in the Maritimes is projected to increase by 400 MW in the next ten years. This amount includes the 200 MW firm capacity sale to Hydro-Québec that will expire on March 31, 2011.

The Maritimes 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 brief interruptions in 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.

Extreme weather conditions are not expected to have any effect on the Maritimes' fuel supplies for generating facilities. Sufficient on-site fuel reserves are maintained for all fossil-fired generation. All plants equipped to burn Orimulsion, for which Venezuela is the single source supplier, can be switched to burn oil. Although the reliance of electric generation on the natural gas infrastructure is increasing, only about 8% of generators in the Maritimes currently use natural gas.

[12] https://www.npcc.org/Member/SecuredFiles/TaskForces/TFCP/CurrentYear/2004%20Maritime%20Triennial%20ReviewRCC.pdf

Transmission — No transmission constraints have been identified within the Maritimes during the 2005–2014 assessment period. New transmission facilities for the Maritimes include the following:

- The Maine Public Service Company (MPS) is planning to construct a 138-kV intra-area transmission line from Limestone, Maine, to the Canadian border near Hamlin, Maine. The purpose of this project is to ensure that the reliability and integrity of the MPS transmission grid are maintained under scenarios of reduced on-system generator availability and peak demand growth. This proposed line would connect to a new 138-kV transmission line in New Brunswick that would extend from the border to near the town of Grand Falls, New Brunswick. As the project is still going through the regulatory approval process in Maine, other options are being considered in the event it is not approved, including conducting an open request for proposal (RFP) process for additional generation capacity in Maine, or opening an existing 138-kV line in New Brunswick and constructing a second intra-area 138-kV line to Tinker, Maine.
- Construction of a second 345-kV interconnection between New Brunswick and New England is scheduled to begin in 2005/2006. This new line will connect Point Lepreau, New Brunswick, to Orrington, Maine, and it has a targeted in-service date of December 2006.

  Interregional transmission transfer capabilities were reviewed for the Maritimes in the July 2004 NPCC document: *Review of Interconnection Assistance Reliability Benefits*. (https://www.npcc.org/publicFiles/documents/interconnectionAssistanceReliabilityBenefits/currentYear/RCC_Approved_CP-8_Tie_Benefit_Report.pdf).

  A review of the transfer capabilities of the proposed second tie between New Brunswick and New England is contained in the March 2005 NPCC document *Addendum — Review of Interconnection Assistance Reliability Benefits*. (https://www.npcc.org/publicFiles/documents/interconnectionAssistanceReliabilityBenefits/currentYear/2nd%20NB%20Tie%20Addendum(rcc).pdf).

  The July 2004 review estimated that the range of tie benefit in 2006 for the Maritimes is 930–1,200 MW. The March 2005 review confirmed that the second tie between New Brunswick and New England could provide up to 300 MW of additional tie benefit to the Maritimes. This second interconnection also significantly improves the reliability of the Maritimes system, since loss of either of the two ties to New England will no longer result in the separation of the Maritimes from the interconnected New England power system.

The blackout of August 14, 2003, created a frequency disturbance that activated a special protection scheme (SPS) to trip generation in the Maritimes area. The SPS tripped 300 MW of generation, and the Maritimes system stabilized. The SPS performed according to its design, and at this time there are no modifications planned for the SPS.

Operations — The addition of the second 345-kV tie between New Brunswick and New England will improve system reliability, stability, and efficiency in addition to expanding competition and electric energy transfers between areas.

No local environmental and/or regulatory restrictions are in effect that could curtail the availability of capacity in the Maritimes. However, the Kyoto Protocol, which was ratified by the government of Canada, calls for a 6% reduction from the 1990 levels of greenhouse gas emissions to be achieved between 2008 and 2012. Initiatives to achieve this reduction may include a reduction in electric energy exports from the Maritimes.

New England Area

Demand—Under expected weather conditions, New England peak demand (summer) is projected to be 26,355 MW in 2005 and 30,180 MW in 2014. This forecast represents a compound annual growth rate of 1.5%. Under the reference load forecast at expected weather, annual peak demands have a 50% probability of being exceeded.

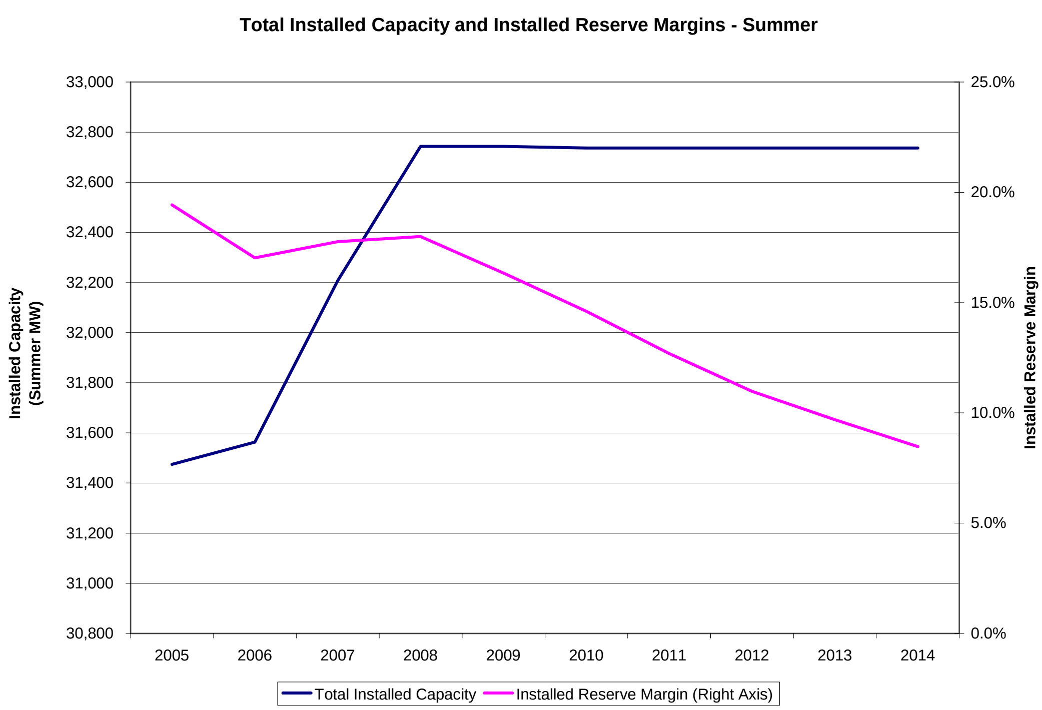
Section 5.2 of NPCC Document B-08, *Guidelines for Area Review of Resource Adequacy*, requires each NPCC area to evaluate proposed resources relative to the need to reliably meet projected demand. Under more extreme weather, New England peak demand (summer) is projected to be 27,985 MW for 2005 and 32,050 MW for 2014. This extreme forecast represents a compound annual growth rate of 1.5%. The forecasted peak demands under more extreme weather have a 10% chance of being exceeded.

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

Compared with last year's assessment, the annual peak demand forecast for 2005 and 2013 has been increased. Compared with last year's load forecast, peak loads have increased by 0.2% for 2005 and 3.3% for 2013. The changes are primarily due to updated weather and economic drivers used in the load-forecasting methodology. ISO-NE's load-forecasting department uses a monthly analysis for the summer season. This monthly methodology captures the weather and economic variations associated with a month rather than an entire season.

Resources — *Figure 15* illustrates the total installed capacity as well as the installed reserve margins forecasted for the 2005–2014 assessment period.

Figure 15: Installed Capacity and Installed Reserve Margins



Installed reserve margins are expected to be sufficient to satisfy the reference New England demand forecast throughout the assessment period. Reserve margins are at the greatest in 2005 with a margin of 19.4% and slowly decline to the minimum of the assessment period of 8.5% in 2014. The reserve margins reflect firm capacity purchases of about 460 MW per year with the exception of 2005 where capacity purchases are about 560 MW. No generating unit retirements have been identified throughout the assessment period and new generation totaling about 1,380 MW is assumed to commercialize by the end of 2007.

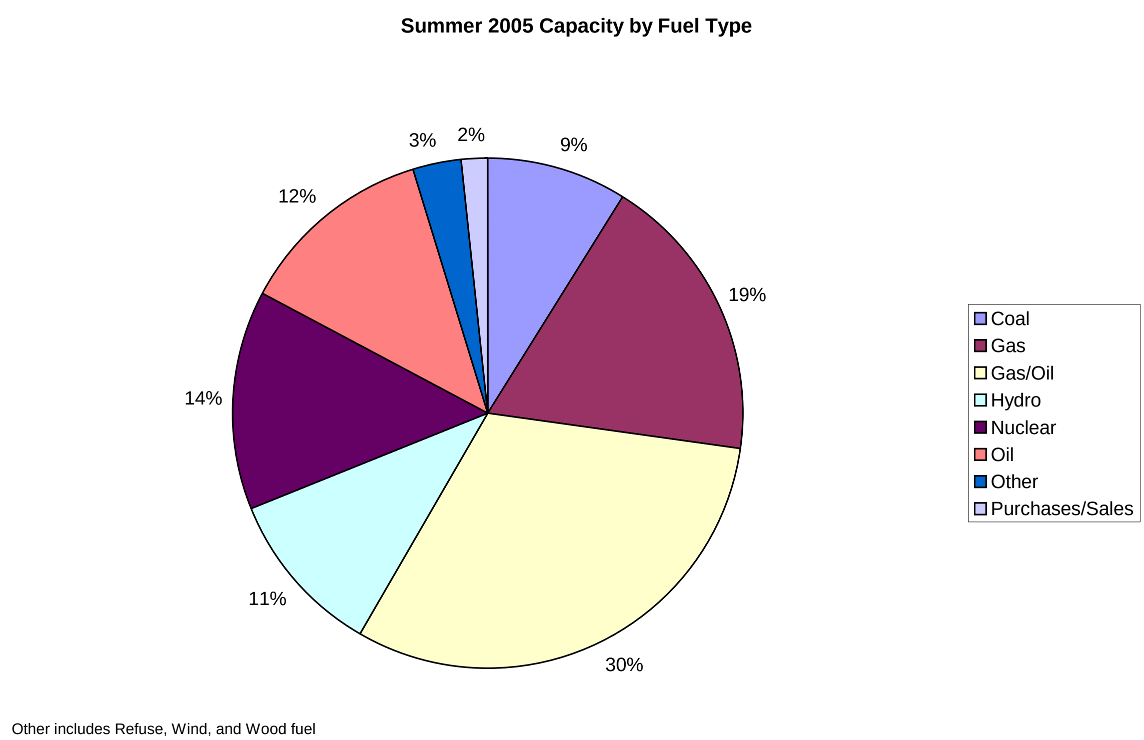
Last year, projected reserve margins ranged from 23.6% in 2007 to 14.8% in 2013. The primary factors associated with the decline from last year's forecasted reserve margins are the updated load forecast coupled with about 200 MW of unit deactivations and retirements in the past year.

ISO-NE anticipates that New England will meet the NPCC resource adequacy criterion of 0.1 days/year LOLE through 2010 assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. New capacity will be needed beyond that year to meet the reliability criterion.

To meet critical near-term electric system reliability needs in southwestern Connecticut for the next four years, ISO-NE has secured emergency energy resources in southwestern Connecticut. The resources provided about 218 MW during the summer of 2005 and will provide up to 255 MW by the summer of 2007 from emergency generation and demand-response resources, including reductions in electricity use and conservation resources.

Fuel — As *Figure 16* illustrates, New England's generating capacity by fuel type is diversified. No constraints are anticipated in fuel supply or delivery to the generators during the summer peak demand seasons.

Figure 16: Summer 2005 Capacity by Fuel Type



During winter, however, due to a high demand for natural gas for home and commercial heating needs, the availability of natural gas to fuel the generation sector is a concern. In January 2004, New England experienced extremely cold temperatures coupled with high electrical demand. During this cold snap, more than 9,000 MW was out of service, which caused ISO-NE to go into emergency operating procedures on January 14, 2004. As a result of this experience, ISO-NE and New England market participants developed *Appendix H to Market Rule 1, Cold Weather Event Operations*. The primary features of this new procedure are to:

- improve the availability of information about natural gas supply and transportation for use by the ISO-NE operations personnel;
- improve the information provided to regional market participants regarding potential cold weather events and an assessment of power system conditions during those events; and
- in extreme cases, shift the day-ahead energy market timeline to allow for early commitments of natural gas generators in anticipation of possible natural gas supply or transportation constraints and operable capacity shortages on the bulk power system.

More information on Appendix H of Market Rule 1 can be found on the ISO-NE's Web site: http://www.iso-ne.com/regulatory/tariff/sect_3/Market_Rule_1_Appendix_H.doc

Transmission — The New England area bulk transmission system is comprised mostly of 115-, 230-, and 345-kV circuits. Transmission lines in northern New England are generally longer in length and fewer in number than in southern New England. The increased transmission density in southern New England reflects the larger load and power supply concentrations. The New England area is interconnected with New York through two 345-kV ties, one 230-kV tie, one 138-kV tie, three 115-kV ties, one 69-kV tie, and one 330-MW HVDC tie. Currently, New England and New Brunswick are connected through one 345-kV tie (except for Aroostook and Washington Counties in Maine, which are served radially from New Brunswick), with a second 345-kV tie planned. New England also has two HVDC interconnections with Québec: a 225 MW back-to-back converter at Highgate in northern Vermont, and a +/- 450-kV dc line with terminal configurations allowing nonsimultaneous operation of either a 690 MW connection at Comerford in northern New Hampshire or a 2,000 MW connection at Sandy Pond in eastern Massachusetts.

Over the ten-year assessment period, ISO-NE's *2004 Regional Transmission Expansion Plan* (RTEP04) identified 246 reliability transmission upgrades and additions, costing a total of between $1.5 billion and $3 billion, that are necessary to reinforce the system and create stronger links between generation and demand centers. More information relating to these 246 projects can be found in the RTEP04 summary report located on ISO-NE's Web site (http://www.iso-ne.com/trans/rsp/2004/RTEP04_Exec_and_Summary_Report_Final_Publication.pdf).

Operations — In future years, several New England states will have lowered generating emission threshold guidelines. To comply with these stricter guidelines, generating plants will need to retrofit their facilities, thus requiring down time. ISO-NE will closely coordinate the maintenance schedule needs of these generating units to assure that system reliability is maintained at all times.

New York

Demand — Energy consumption is forecast to grow at an average annual rate of 0.8% through 2014. The New York area is a summer-peaking system, and summer peak demands are expected to grow at an average rate of 0.9%, through 2014. This compares with 1.0 and 1.2% growths, respectively, projected in the 2004–2013 assessment conducted by the RAS in 2004.

Resources — The New York State Reliability Council (NYSRC) has determined that an 18% installed reserve margin for the New York Control Area (NYCA) is required to meet the NPCC and more stringent NYSRC resource adequacy criterion. As a conservative assumption, the generation of the 18% installed reserve margin requirement for New York does not rely on external installed capacity (ICAP) purchases, even though 2,500 MW of these purchases typically participate in the NYCA ICAP market. It does assume 2,000–2,400 MW of tie benefits from New York's neighboring balancing authorities and transmission operators.

Given current demand projections, New York would need 430 MW of additional resources to meet a projected 18% level through 2014. This projection assumes the continuation of the current level of external ICAP of about 2,500 MW and the continuation of special case resources (SCRs) of about 900 MW. SCRs are loads capable of being interrupted, and distributed generators rated at 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that provide energy/load curtailment only when activated in accordance with the NYISO *Emergency Operating Manual*.

The resources necessary to meet this projected requirement will likely be procured through the NYISO ICAP market. Currently, new capacity totaling 1,900 MW is under construction in New York. Studies are currently in progress to assess the deliverability of this capacity within New York State and the New York City-Long Island zones.

In addition to the above statewide requirement, the NYISO imposes locational capacity requirements on load-serving entities located within New York City and Long Island due to their geography, as described in the locational installed capacity requirements study of February 2005. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the geographic boundaries of that locality. The New York City locational capacity requirement is 80% of the demand level, and the locational capacity requirement is 99% of the demand level within Long Island.

Long Island continues to meet its projected demand growth with the addition of gas turbine generation. In addition to the ten gas turbines that were added in 2002, 100 MW of gas turbines were added in 2003 and 2004, and about 120 MW of gas turbines were added for the summer of 2005. At the current locational requirement level, more than 500 MW of additional new capacity will be needed by 2014 to meet projected demand growth.

New York City has recently met its locational capacity requirement by the addition of a 288-MW, combined-cycle plant. If the projected locational requirements stay at 80%, the plants currently under construction, along with special case resources, would be adequate to meet the projected demand growth through 2014.

Transmission — Based on the present load forecast, planned transmission facilities, and projected generation resources, including proposed generation additions and associated transmission upgrades, the New York bulk power transmission system is judged to be adequate through 2014. Significant transmission projects currently being proposed include the following:

New York-Proposed Bulk Power Transmission Facilities

Terminals		Voltage	Year	Number of Circuits	Miles
Dunwoodie	Sherman Creek	138	2005	1	7.8
Riverhead	Canal	138	2005	1	16.4
East Garden City	New Superconductor Substation	138	2006	1	0.38
Bergen	West 49th Street	345	2006	2	7.5
Sayerville	West 49th Street	250 (HVDC)	2006	1	36
Liberty	Goethals	230	2006	1	0.62
Northport	Norwalk Harbor	138	2006	1	11
Mott Haven	Dunwoodie	345	2007	2	10
Mott Haven	Rainey	345	2007	2	4.1
Sprain Brook	Sherman Creek	345	2007	1	10
Newbridge Rd	East Garden City	138	2007	1	4

New York-Proposed Bulk Power Transmission Facilities

Terminals		Voltage	Year	Number of Circuits	Miles
Newbridge Rd	Ruland Rd	138	2007	1	9.1
Duffy Ave Converter Station	Newbridge Rd	345	2007	1	1.7
Newbridge Rd	Newbridge Rd	345/138	2007	2	NA[13]
Holtsville GT	Brentwood	138	2007	2	12.4
Brentwood	Pilgrim	138	2007	1	4.6
Ramapo	Tallman	138	2007	1	3.2
Tallman	Burns	138	2007	1	6.1
Duffy Ave Converter Station	PJM	500	2007	1	65
Station 80	Station 82/Mortimer	115	2007/2008	2	3.5
Station 82	Station 67	115	2007/2008	1	2.4
Station 80	Station 67	115	2007/2008	1	5.9
Station 82	Station 48	115	2007/2008	1	9.5
Station 48	Station 7	115	2007/2008	1	7.5
Station 121	Station 230	115	2007/2008	1	5.7
Station 80	Station 80	345/115	2007/2008	1	NA[13]
Sterling	Off Shore Wind Farm	138	2008	1	10.1
Riverhead	Canal	138	2010	1	16.4
Hurley Ave	Saugerties	115	2011	1	11.1
Pleasant Valley	Knapps Corners	115	2011	1	17.7
Saugerties	North Catskill	115	2012	1	12.2

Ontario

Demand — Ontario has typically experienced its annual peak demand in the winter. However, in three of the last five years, Ontario's annual peak demand occurred during the summer due to extreme weather conditions. Based on normal weather conditions, Ontario is forecast to become a summer-peaking area in 2007.

Median energy consumption is forecast to grow at an average annual rate of 0.9%, the same as last year's forecast growth rate. Both the current and previous forecasts predicted an average annual increase of 0.7% for the winter peak demand, and the current forecast projects summer peak demand increasing at a rate of 1.3%, compared with last year's 1.1% average annual growth rate.

Resources — Brighton Beach and Kirkland Lake generation additions, representing about 600 MW of capacity, became available in 2004. An addition of 515 MW of nuclear generation is expected after the 2005 summer following reactivation of Pickering A Unit 1. Recent capacity additions have improved Ontario's supply outlook in the short term. However, additional Ontario electricity supply and demand-side measures are required to maintain supply adequacy into the future. The 1,148-MW, coal-fired Lakeview thermal generating station ceased operation at the end of April 2005. The Ontario government is committed to phasing out coal-fired generation in the province (about 6,400 MW in addition to the Lakeview station) when replacement resources are available. Since coal-fired generation accounts for about 21% of Ontario's current generating capacity, a substantial amount of new supply, refurbished generation or additional demand-side resources will be required. By the summer of 2015, a deficiency of 4,239 MW must be addressed. In the interim, it will be important to maintain the reliability of existing coal-fired generating stations despite their planned shutdown. The IESO will continue working with the provincial government to ensure an appropriate amount of replacement supply or demand initiatives, at suitable locations, is reliably available before the coal-fired generators are shut down.

[13] transformer, line mileage not applicable

Two Bruce A and two Pickering A nuclear units representing 2,570 MW of capacity remain shutdown. Plans for their reactivation remain under consideration. These units will be included in future assessments if plans to return them to service are confirmed.

Under median demand growth assumptions, Ontario needs to secure additional resources, above those that currently exist or are under construction, starting in 2007, in order to meet the NPCC resource adequacy criterion through 2008 and beyond.

To spur new supply development, the Ontario government initiated RFP seeking up to 300 MW of renewable energy capacity and up to 2,500 MW of new generating capacity and/or demand-side initiatives to be developed as soon as practicable. To date, the government has announced ten projects totaling 395 MW of renewable energy and four projects totaling 1,675 MW of clean generating capacity and demand-side initiatives. All 14 projects are contracted to be available by the end of 2007. Construction of two of these projects has started with construction of more of the projects expected to begin later this year and continue in 2006. Additional contract announcements from the 2,500-MW RFP are expected. As part of the RFP requirements, the IESO has identified that significant new capacity or demand-side management is required in downtown Toronto and the greater Toronto area (GTA). The resolution of these localized reliability concerns may be addressed by further announcements under the 2,500-MW RFP. If these requirements are not addressed by the RFP, then other plans will need to be developed and implemented in the near term.

A second renewables RFP was issued in April 2005 for 1,000 MW from projects ranging in size from 20 to 200 MW, to be in service by October 31, 2008.

IESO adequacy assessments include only those projects that are under construction or that have power supply contracts with the Ontario Power Authority (OPA).

The recently formed OPA has responsibility for long-term supply, integrated power system planning, development of conservation and demand-related measures, and development of retail rate programs. This assignment of responsibilities has been implemented to provide assurance of adequate future electricity supply for Ontario.

The majority of the proposed new generation facilities in Ontario are gas fired. If all of these facilities were to be built, the volume of gas consumed for electricity generation would increase substantially. However, fuel supply is expected to be adequate to meet forecast electricity demand and potential infrastructure issues will be addressed in conjunction with the coal phase-out.

A joint gas-electricity working group has been established with the IESO as a member to identify near- and long-term issues (in particular related to communications, market alignment, and infrastructure) and to ensure solutions are developed in a timely manner. These activities will be coordinated with those of other Ontario stakeholders including the Ontario Energy Board (OEB) and the OPA.

The phase-out of coal-fired generation will present a unique challenge for coal supply contracting. Traditionally, coal has been purchased under long-term contracts. For the affected stations, a delicate short-term contracting balance may be required to ensure sufficient coal is delivered to maintain operability until replacement supply is achieved, without leaving surplus coal on the ground after plant retirement. This has already been successfully managed for the Lakeview shutdown.

Transmission — Significant transmission reinforcement is required in the 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 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 plant in 2005. In order to maintain an acceptable level of system reliability in the GTA, new shunt capacitors (1,100 Mvar) have been installed at four transformer stations and the first phase of a new 500/230-kV transformer station, Parkway transformer station, has been placed in service. Major transmission projects have been proposed to increase internal transfers and Ontario's import and export capabilities. These are in various stages of development:

- A new 230-kV, 845-MVA (mega volt amperes) phase angle regulator (PAR) on Ontario-Michigan interconnection circuit L4D replacing the old PAR is now in service and at neutral position. An operational agreement is being negotiated with MISO for the operation of this PAR and the PAR on circuit L51D. Until such an agreement is in place, the PARs will only be operated off neutral tap to prevent shedding firm load.
- A new 48-mile, 230-kV double circuit line between the Allanburg and Middleport transformer stations has been proposed to increase the summer transfer capability of the Queenston Flow West (QFW) interface by about 800 MW. The enhanced QFW interface should permit less constrained operation of the generation facilities within the Niagara zone and improve the utilization of the New York-Niagara import capability. This line is under regulatory review.

Operations — No major operating issues currently exist that would impinge on Ontario reliability over the ten-year assessment period. IESO has achieved significantly better blackstart preparedness after the blackout in August 2003 by procuring additional blackstart capability and implementing annual line energization tests in conjunction with existing generator blackstart tests.

Québec

Demand — The internal peak demand forecast for the 2005–2006 winter at normal conditions is 35,767 MW and is expected to grow at an annual average rate of 0.66% to reach 37,951 MW for the winter of 2014/2015. In addition, Hydro-Québec has a firm export commitment of 455 MW (without losses) to neighboring networks outside Québec for the whole period.

From 2005/2006 to 2013/2014, Québec will have available 983 MW of industrial interruptible load during the winter season. This is 468 MW higher relative to last year.

For 2005, the internal electrical usage is expected to be 186 TWh. Between 2005 and 2014, the electrical energy demand will grow at an average rate of 0.90% to reach 202 TWh in 2014.

Resources — In its 2004 interim review of resource adequacy of December 2004, Hydro-Québec demonstrated that the resource requirements had to be about 10% over the annual peak demand to comply with the Québec and NPCC adequacy criteria. The resource requirements for the next two winter peak periods are 9.7 and 10.3%, respectively, and are forecasted to be met under base load forecast scenario. In the case of a high load forecast scenario, new resources would need to be added only for the 2005/2006 winter peak demand month. Hydro-Québec Distribution, responsible for sales and services to Québec customers, will issue calls for tenders for the purchase of short-term contracts or will sign additional interruptible contracts with industrial customers to provide resources to maintain Québec's reliability inside the resource adequacy criterion. From 2007/2008 to 2014/2015, the required reserve margins will meet Québec adequacy criterion.

During 2005, the 526-MW hydroelectric plant Toulnustouc will be commissioned bringing the installed capacity to 32,094 MW for the winter period of 2005/2006. The increase in capacity from 2005/2006 to 2014/2015 is expected to be 3,045 MW. The increase comes from hydro generation plants located on various river systems (2,423 MW) and from a 547-MW, gas-fired, combined-cycle plant. The overhaul of the nuclear station Gentilly 2 is planned from September 2010 to April 2012, which will eliminate a capacity restriction of 40 MW.

In 2005, 99 MW of new wind power capacity will be installed in Québec. By 2012, the installed wind capacity will increase by about 1,200 MW. In this assessment for Québec, wind power capacity is not included. Hydro-Québec is in the process of evaluating the capacity value of installed and projected wind power generation.

Hydro-Québec's energy is largely produced by hydro generating stations, located on different river systems geographically distributed; the major ones with multiyear storage capability. For planning and day-to-day operation of the Hydro-Québec system, Hydro-Québec can rely on those multiyear reservoirs (water reserves) and on some other nonhydroelectric resources, allowing Hydro-Québec to cope with negative inflow variations. Those resources include, among other things, fossil generation. Based on the present level of water reserves in reservoirs and the availability of other nonhydroelectric resources, generation shortage problems are not expected for the short and medium term.

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

Transmission — Hydro-Québec TransÉnergie will add several transmission lines to integrate additional generation particularly for wind plant and hydroelectric projects.

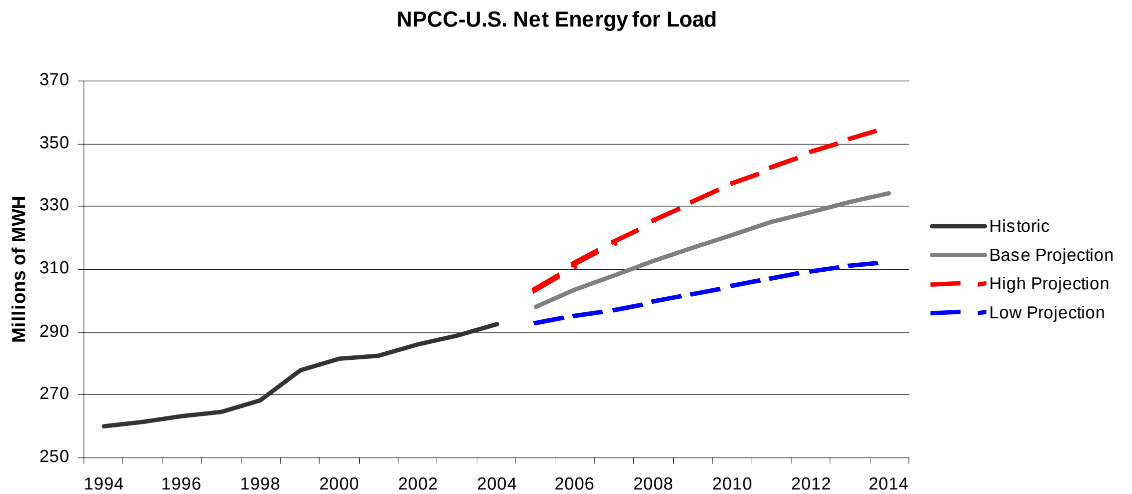
Operations — The following ongoing transmission projects were initiated following the 1998 ice storm:

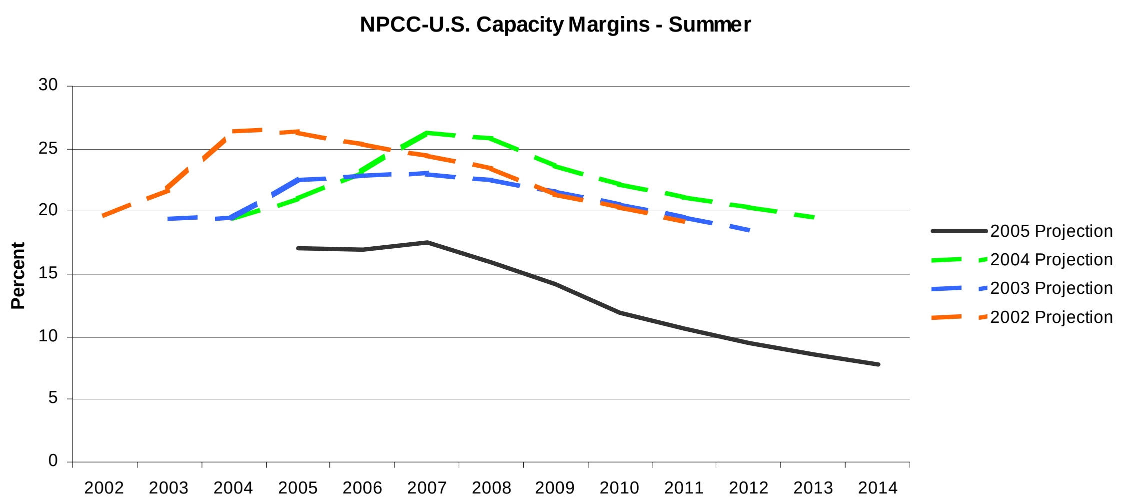
- The installation of semiconductor devices at the Lévis and Boucherville 735-kV substations, planned respectively for 2007 and 2009, which will be normally operated as dynamic shunt compensators on a steady-state basis. In the event of severe icing conditions, these devices will be transformed to sequentially allow the injection of high dc current in 735- and 315-kV lines to melt the accumulated ice on conductors.
- The reinforcement of more than 237 miles of existing 735-kV line and 116 miles of 315-kV line, planned in 2006 and 2007, to meet the new requirement for ice loading.

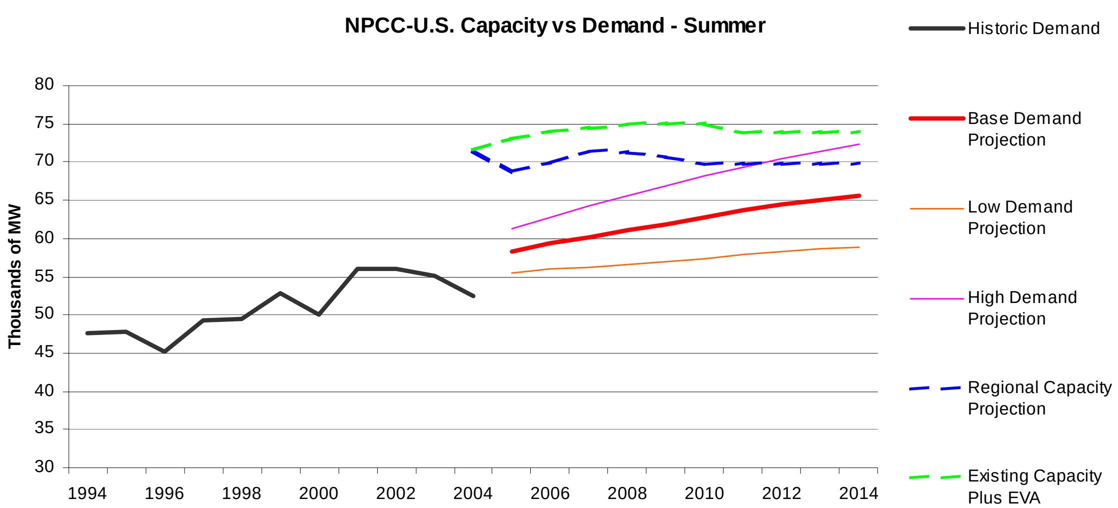
Following the blackout of August 2003, verification of the proper behavior of the HVDC ties was conducted. No change in the transmission planning was brought about. No other operations issues are expected during the 2005–2014 assessment period.

NPCC is a voluntary, nonprofit organization. Its 36 members represent transmission providers, transmission customers and ISOs serving the northeastern United States and central and eastern Canada. Also included are six nonvoting 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 NPCC covers is about one million square miles and includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia. http://www.npcc.org/.

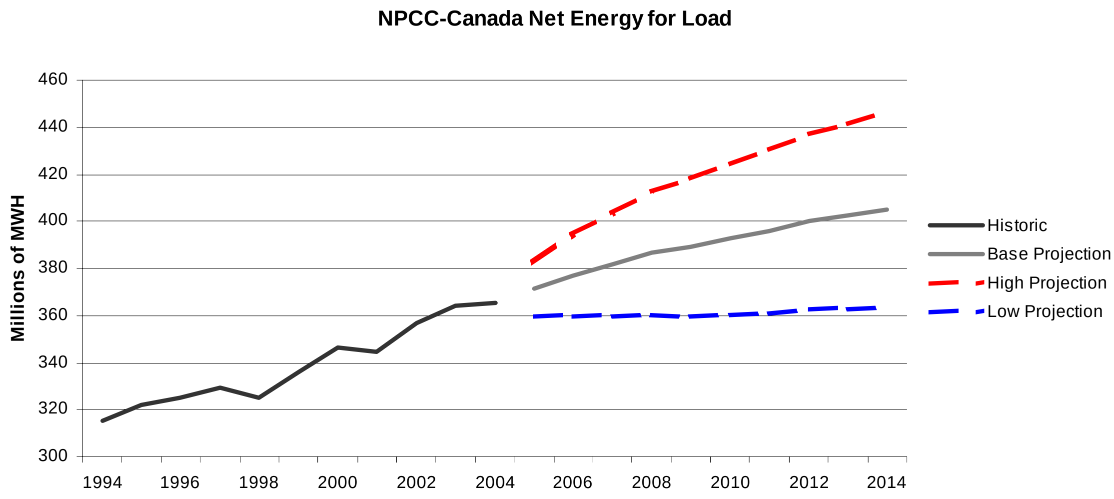
NPCC-U.S. Capacity and Demand

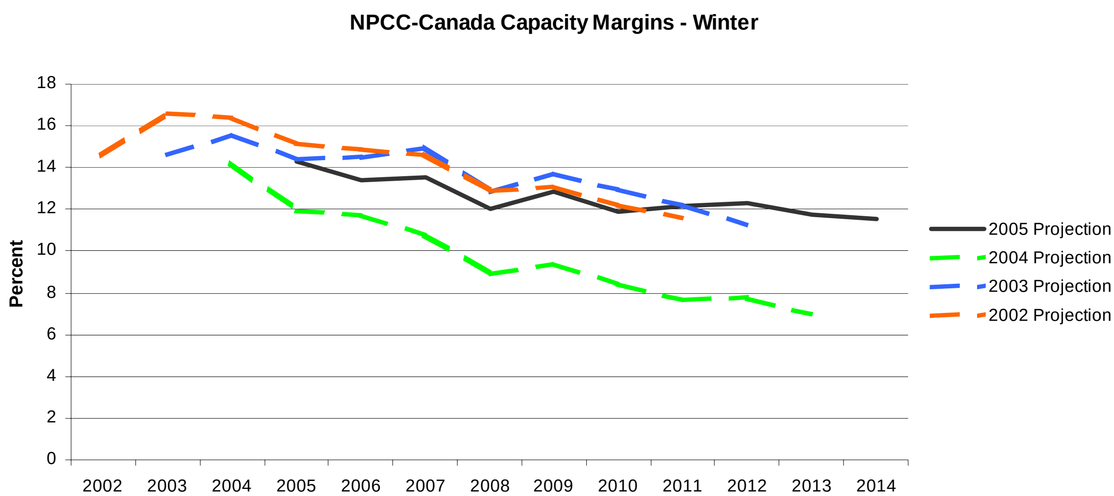


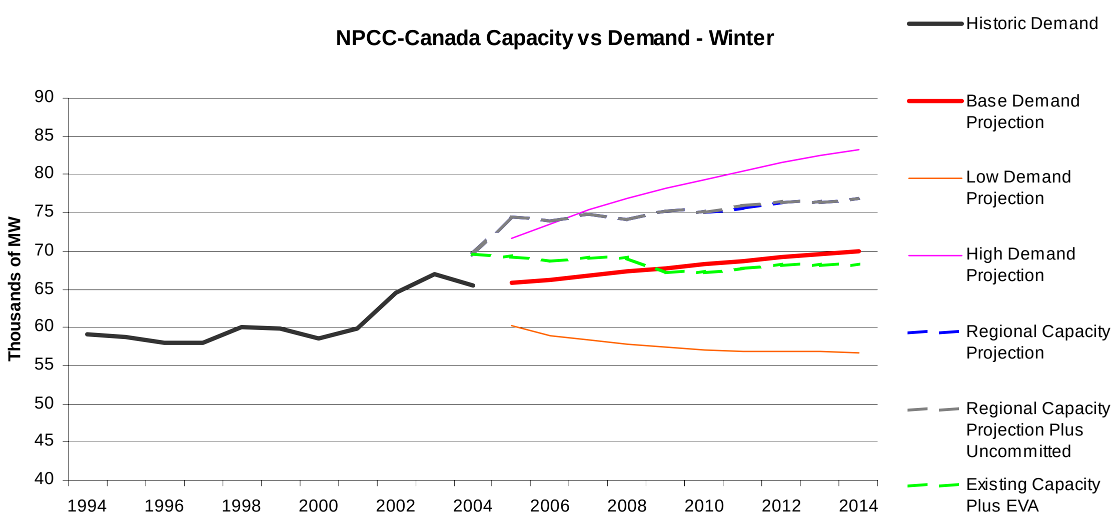




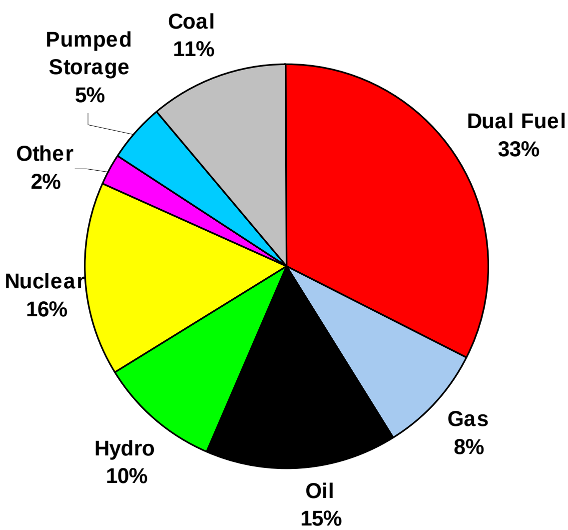
NPCC-Canada Capacity and Demand







NPCC-U.S. Capacity Fuel Mix 2000



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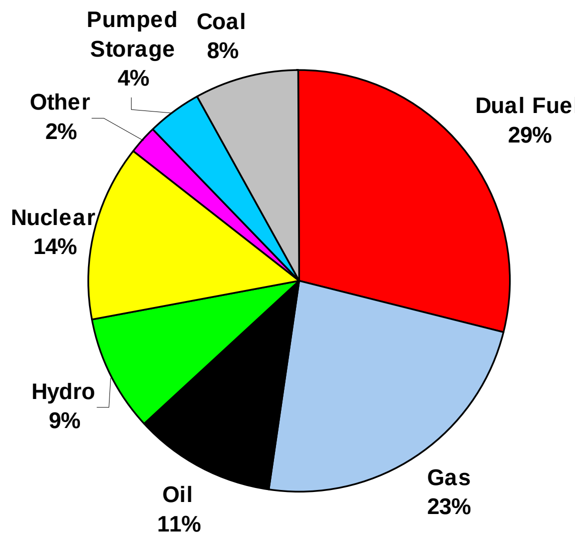
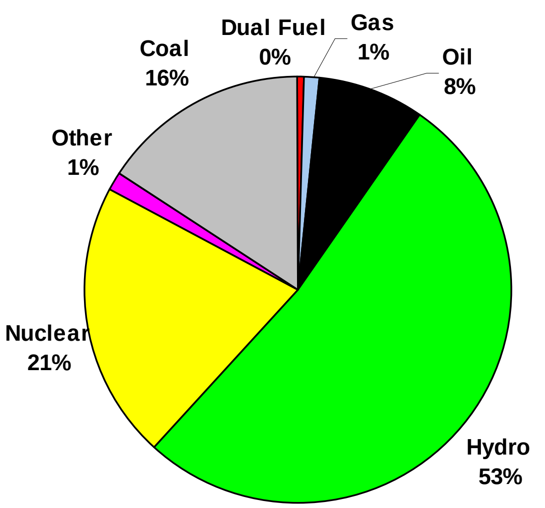
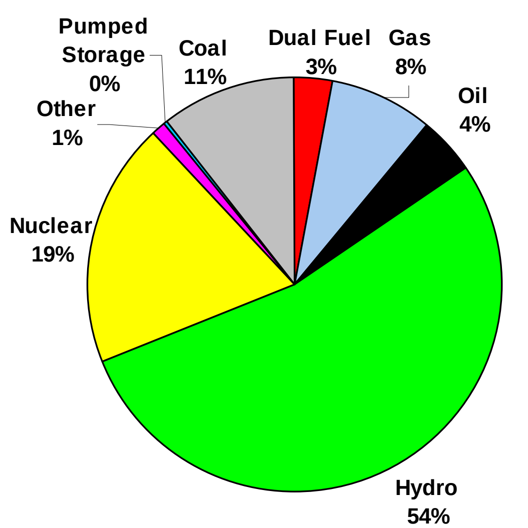


NPCC-Canada Capacity Fuel Mix 2000



NPCC-Canada Capacity Fuel Mix 2010



SERC

SERC anticipates consistent load growth in demand and energy over the next ten years.

Capacity resources in the region are expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the long-term assessment period. Significant merchant generation development has occurred in the SERC region during the past few years, resulting in thousands of MW of excess generating capacity. Much of this merchant generation has not been contracted to serve load within the SERC region or outside the SERC region. However, this generation can be made available as capacity resources to SERC members and others if any necessary transmission improvements are made to ensure a firm and reliable delivery of the resources.

The SERC region has extensive transmission interconnections between its subregions and its neighboring regions (ECAR, FRCC, MAAC, MAIN, MRO, and SPP). These interconnections allow the exchange of large amounts of firm and non-firm power and allow systems to assist one another in the event of an emergency.

Coordinated planning studies are conducted within 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 1,740 miles of 230-kV lines and 285 miles of 500-kV lines. SERC members invested more than $1 billion in new transmission lines and system upgrades in 2004, and they are planning transmission capital expenditures of more than $6 billion over the next five years.

Demand

The projected 2005 total internal peak demand (which includes load associated with load-management programs) for the SERC region was 165,144 MW. This is a 4.8% increase over the actual 2004 peak demand of 157,615 MW. Both of the peak demands were during the summer period, which is typical for SERC. However, the actual 2004 peak was established during a period of lower-than-expected weather temperatures.

The 2006 summer total internal demand forecast is 168,565 MW and the forecast for 2014 is 199,047 MW. The average annual growth rate over the next ten years is 2.1%. This is the same as last year's forecast growth rate. The historical growth rate over the last ten years averaged 2.7%.

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 affect the actual peak demand and energy for the region.

The amount of interruptible demand and load management is expected to decline slightly over the forecast period from 4,986 MW in 2006 to 4,846 MW in 2014.

Resources

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands throughout the long-term assessment period, when committed and uncommitted resources are considered. The projected capacity margin for 2006 is 10.4%, down from the 2005 value of 14.2%. Some entities in SERC have not yet confirmed all their capacity resource for 2006. Therefore, projected capacity margins for 2006 are anticipated to increase as purchase contracts are secured. A portion of these contracts will likely include agreements with current uncommitted resources within the region. Capacity margin calculations assume the use of load management and interruptible contracts at the time of the annual peak.

Although the SERC region does not implement a regional reserve requirement, members adhere to their respective state commissions' regulations regarding maintaining adequate resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak demand. The transmission system has been planned, designed, and operated such that the region's generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC guidelines to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no constraints that would reduce the availability of committed capacity resources. In addition, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets, indicating that a portion of the uncommitted resources is currently deliverable.

The projected 2006 capacity mix reported for SERC is about 48% coal, 17% nuclear, 10% hydro/pumped storage, 19% gas/oil, and 6% of purchases and miscellaneous other capacity. This capacity mix includes only committed generation. The majority of planned capacity additions are gas/oil-fueled combustion turbine or combined-cycle units. However, there are plans in the ten-year planning horizon for coal-fired and nuclear plant additions (e.g., the 1,250-MW Browns Ferry Unit 1 for March 2007).

Energy

The forecast growth rate in energy usage over the next ten years is 1.7%, down from last year's forecast of 2.0%. The historical ten-year average growth rate is 2.3%.

Generation Development

Significant merchant generation development has occurred in SERC since 1998, especially in the Southern Company and Entergy subregions. Most of this merchant generation was intended for sale in the wholesale markets. However, 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 the SERC-reported capacity margins.

The amount of generation that is connected or has requested connection to the transmission system demonstrates the extent of generation development in the region. While previous SERC surveys of generation development focused only on the growth of the generation resources within the region, this year's survey sought a more accurate representation of future generation resources, taking into account the potential retirement of some existing units. *Table 4* contains a summary of generation interconnection requests. This table includes both utility and merchant generating plants. Requests reported as "signed/filed" are believed to have a somewhat higher probability of being built than those listed as "requested."

Table 4: In-Service Year of Added Generation (MW)

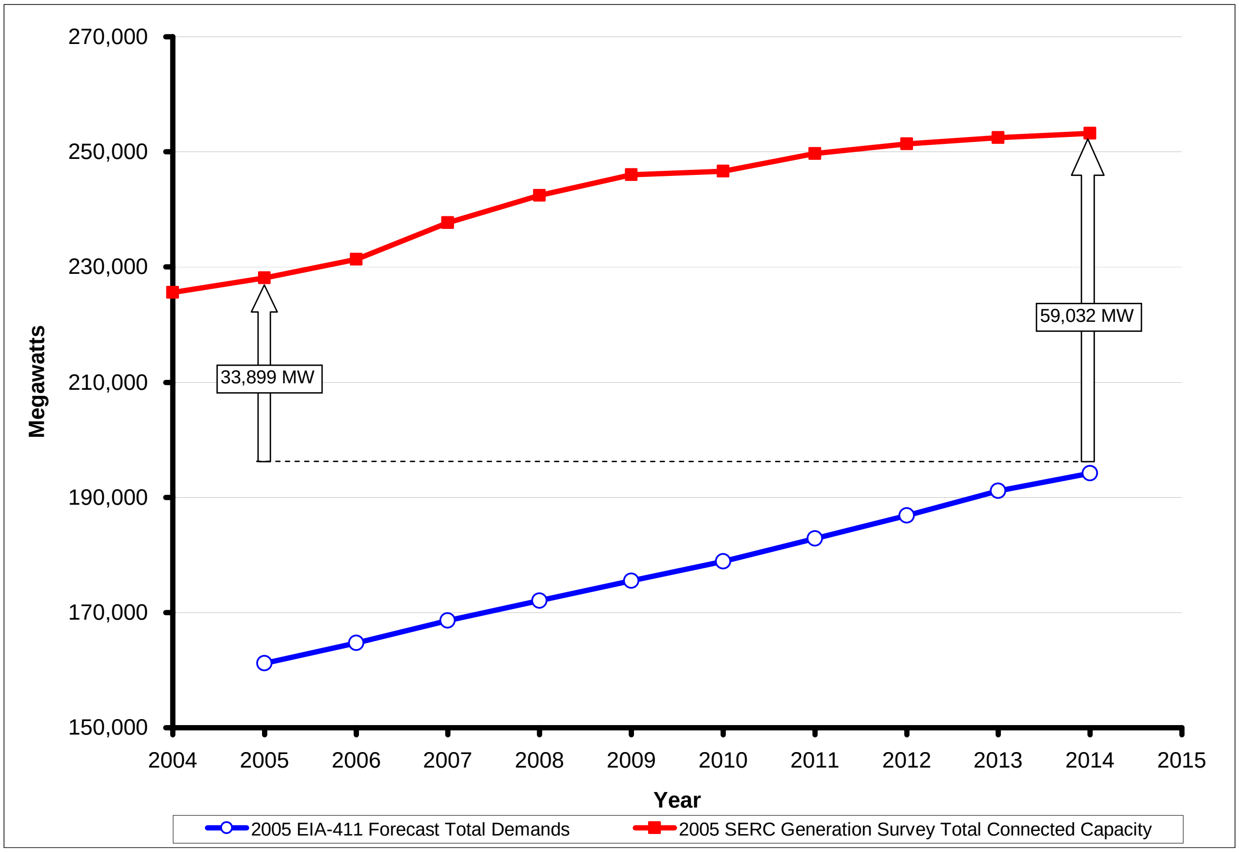
Current Status of Generation Plant Development	In-Service Year of Added Generation (MW)									
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Interconnection Service Requested, Only	797	240	2,257	2,105	710	50	1,341	942	1,062	766
Interconnection Agreement Signed/Filed or Equivalent to Native Load	1,686	2,988	4,118	2,866	3,037	650	1,838	750	4	0
Retirements	0	7	30	178	183	108	85	0	0	0
Annual Totals	2,483	3,221	6,345	4,793	3,564	592	3,094	1,692	1,066	766
Cumulative Totals	**2,483**	**5,704**	**12,049**	**16,842**	**20,406**	**20,998**	**24,092**	**25,784**	**26,850**	**27,616**

Source: SERC Reliability Review Subcommittee 2005 report to the SERC Engineering Committee

In previous surveys, generation additions had totaled more than 4,000 MW annually through 2009. This year's survey indicates less than 4,000 MW annually for every year except 2007 and 2008. In the near-term years of 2005 and 2006, where construction plans are more definite, capacity additions are expected to reach only 2,500 MW and 3,200 MW, respectively. In the generation facility construction planning horizon (two to three years), significant speculation exists about the amount of generation that will be added (6,400 MW and 5,000 MW for 2007 and 2008, respectively), but the amount of generation to actually be constructed will likely change before the next annual survey, as the need approaches to either start construction or delay/cancel a generation project. The majority of generation development was reported for the first seven years and totals more than 24,000 MW by 2011, but this is in stark contrast to the 43,000 MW reported to be operable by 2009 in last year's survey. Beyond 2011, the reported generation development decreases sharply.

As of December 31, 2004, SERC's Generation Development Survey indicated that the total generation connected to the transmission systems in SERC was 225,617 MW, an increase of more than 2,000 MW in one year. An additional 2,483 MW of generation was planned to be connected to the transmission systems by July 1, 2005, bringing the total to 228,100 MW. These values differ slightly from the EI-411 data reported in Table 2 due to inoperability and mothballed units. The current total generation connected to the SERC systems exceeds projections for SERC regional load in 2014 by almost 34,000 MW. If all of the proposed capacity described in *Table 4* is built, installed generation could exceed forecast peak demand by more than 59,000 MW in 2014 (see *Figure 17*). This amount is significantly more than the generation capability needed for reliability/adequacy in the region.

Figure 17: Proposed Generation Development in SERC



Transmission

The existing bulk transmission system within SERC is comprised of 13,441 miles of 161-kV, 19,689 miles of 230-kV, 757 miles of 345-kV, and 8,499 miles of 500-kV transmission lines. SERC member systems continue to plan for a reliable bulk transmission system and plan to add 47 miles of 161-kV, 1,740 miles of 230-kV, and 285 miles of 500-kV transmission lines in the 2005–2014 assessment period. SERC members invested more than $1.1 billion in new transmission lines and system upgrades in 2004, and are planning transmission capital expenditures of about $6.25 billion over the next five years.

SERC member transmission systems are directly interconnected with the transmission systems in ECAR, FRCC, MAAC, MAIN, MRO, 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 standards. The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand and energy requirements and firm transmission reservations during normal system conditions and probable contingency conditions.

Operations

The planned increase in gas-fueled generation in the SERC region will require significant increases in both gas supply and pipeline capacity. Sufficient inventories, fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC members to reduce reliability risks due to fuel supply issues. In addition, the diversity of generating resources serving SERC member loads further reduces the region's risk. No fuel deliverability problems are anticipated and inventories are expected to be adequate throughout the long-term assessment period.

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 SERC-MAIN and SERC-ECAR regional interfaces, and the Southern-TVA, Entergy-Southern, and Southern-VACAR subregional interfaces are affected by these loop flows. The proposed 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. Although no projects have been identified or planned for the sole purpose of relieving loop flow issues, members are relieving constraints that affect transfer capabilities through reliability improvement projects. Inherently, these projects will help to relieve loop flow issues as well.

Coordinated interregional transmission reliability and transfer capability studies for the shorter-term planning horizon were conducted among all the SERC subregions and with the neighboring regions. In addition, coordinated intraregional transmission reliability and transfer capability studies for the longer-term planning horizon were conducted within SERC. These studies indicate that the bulk transmission systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

Subregions

Entergy

The forecast 2006 summer peak demand for the Entergy subregion is 27,895 MW. The summer peak demand is forecast to increase to 31,194 MW in 2014. The average annual demand growth rate is 1.4%. This is lower than the 1.8% projected last year and lower than the 2.4% historical ten-year peak demand growth rate.

The projected capacity margin for the 2006 summer is 5.1%, and declines to -0.4% in 2014. Capacity in addition to that currently planned will be needed to maintain reliability. The large amounts of merchant generation in the subregion could provide the needed capacity and adequate time remains to build new capacity if necessary, therefore the low capacity margins are not a reliability concern at this time.

Planned transmission additions include 443 miles of 230-kV lines and 30 miles of 500-kV lines.

Southern

The forecast 2006 summer peak demand for the Southern subregion is 48,174 MW. The summer peak demand is forecast to increase to 58,354 MW in 2014. The average annual demand growth rate is 2.5%. This is slightly higher than the 2.4% projected last year and lower than the 3.3% historical ten-year peak demand growth rate.

The projected capacity margin is 9.5% for the 2006 summer, and ranges from 7.1% to 3.1% over the remainder of the planning period. Capacity margins decline in the later years of the planning horizon. Capacity in addition to what is currently planned will be needed to maintain reliability. Large amounts of merchant generation in the subregion could provide the needed capacity and adequate time is available to build new capacity if necessary. As a result, the low capacity margins in the later years are not a reliability concern at this time.

Planned transmission additions include 648 miles of 230-kV lines and 125 miles of 500-kV lines.

TVA

The forecast 2006 summer peak demand for the TVA subregion is 29,602 MW. The summer peak demand is forecast to increase to 35,544 MW in 2014. The average annual demand growth rate is 2.3%. This is slightly lower than the 2.6% projected last year and lower than the 2.5% historical ten-year peak demand growth rate.

Projected capacity margin is 9.7% for the 2006 summer, and ranges from 8.3% to 10.8% over the remainder of the planning period. The increase in capacity margin from 2010 to 2011 is due to an expected increase in power purchases by the TVA subregion.

Planned transmission additions include 3 miles of 230-kV lines and 36 miles of 500-kV lines. In addition, plans for several new 161-kV lines are presently being considered.

VACAR

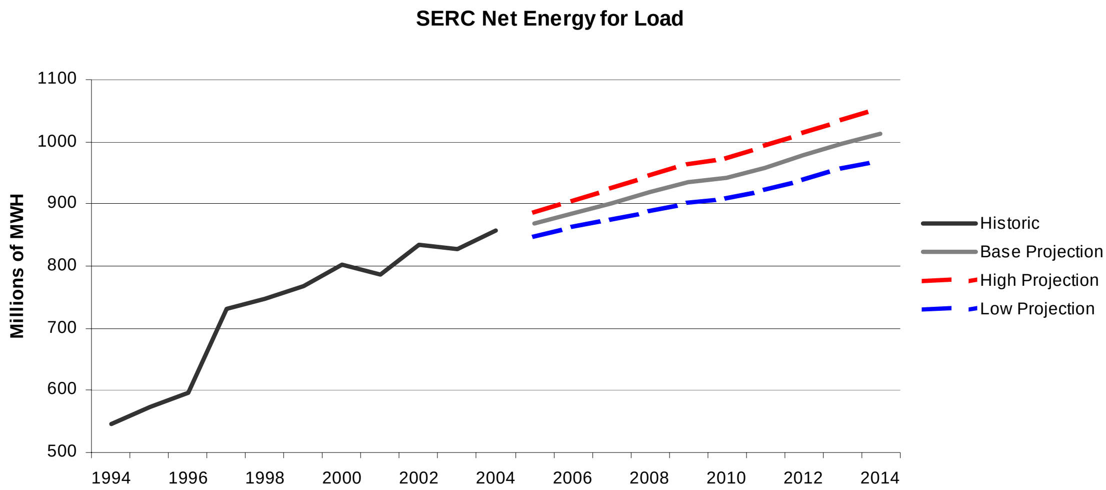
The forecast 2006 summer peak demand for the VACAR subregion is 58,996 MW. The summer peak demand is forecast to increase to 69,109 MW in 2014. The average annual demand growth rate is 2.0%. This is slightly lower than the 2.1% projected last year and lower than the 2.4% historical ten-year peak demand growth rate.

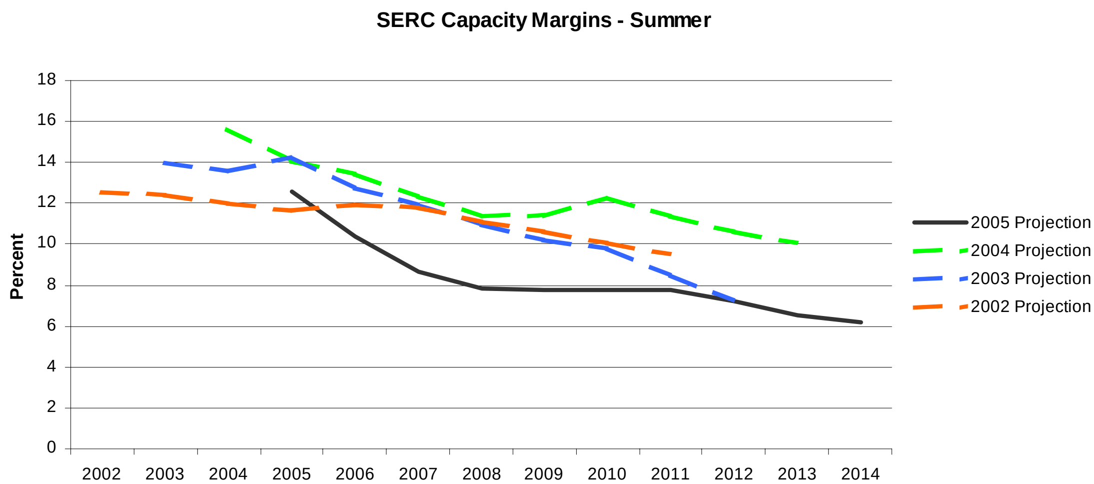
The projected capacity margin is 12.2% for the 2006 summer, and ranges from 11.9% to 9.1% over the remainder of the planning period. Capacity margins decline in the later years of the planning horizon. Capacity in addition to that currently planned will be needed to maintain reliability. Merchant generation currently proposed in the subregion could provide the needed capacity and adequate time is available to build new capacity if necessary. As a result, the low capacity margins in the later years are not a reliability concern at this time.

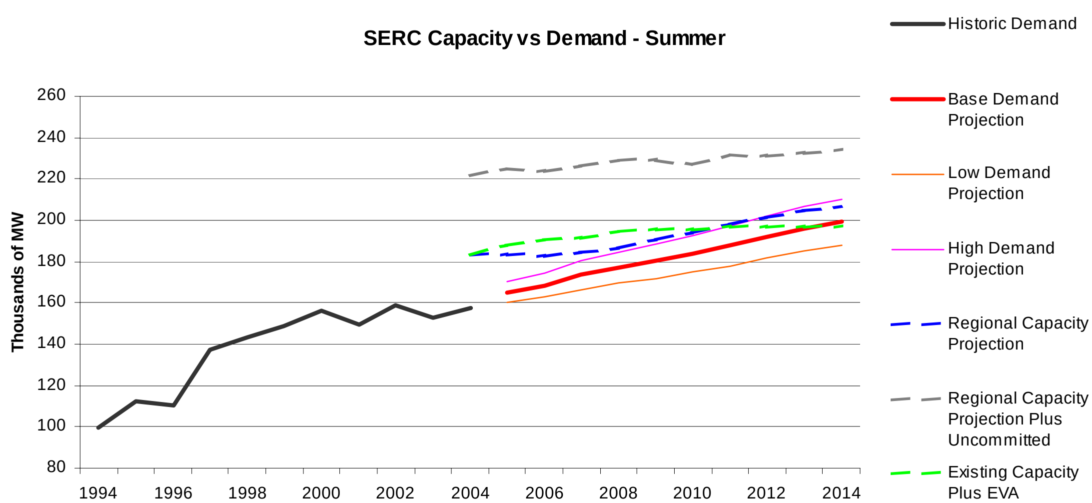
Planned transmission additions include 646 miles of 230-kV lines and 94 miles of 500-kV lines.

SERC membership includes 39 members and ten associate members. The SERC region includes portions of 13 states in the southeastern United States, and covers an area of about 464,000 square miles. SERC is divided geographically into four diverse subregions: Entergy, Southern, TVA, and the Virginia-Carolinas area (VACAR).

SERC Capacity and Demand

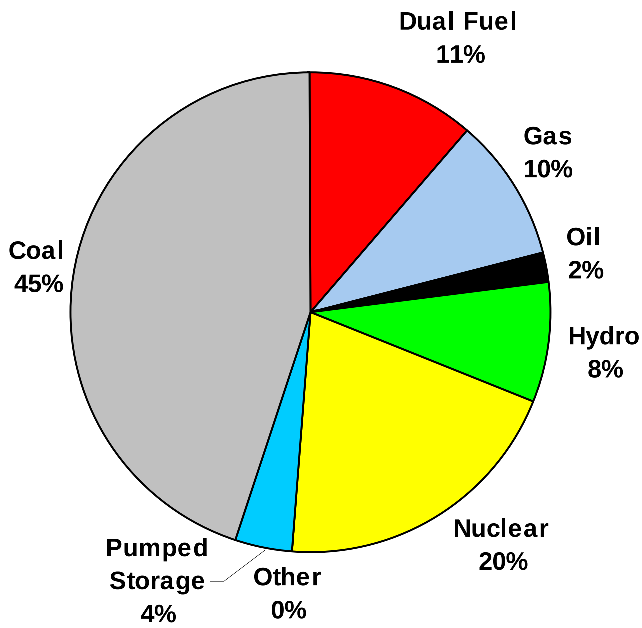




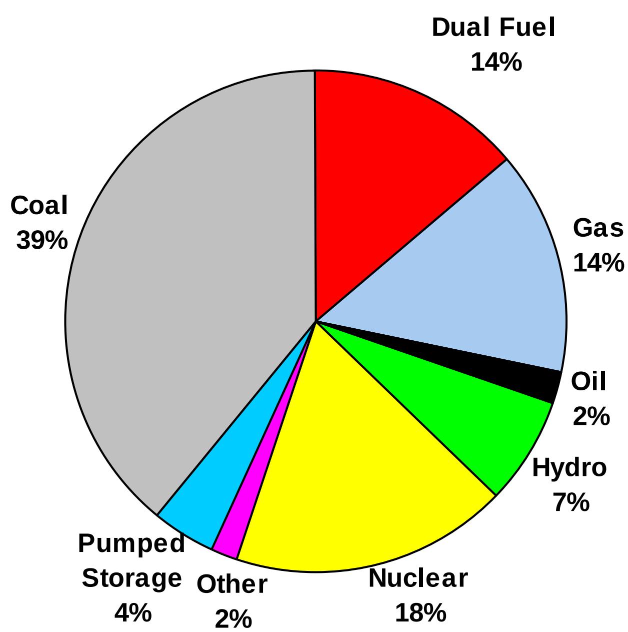


In 1997, former SPP members, Associated Electric Cooperative, Inc., Entergy Corporation, and Cajun Electric Power Cooperative began reporting in SERC. All post-1996 statistics stated herein are based on this change.

SERC Capacity Fuel Mix 2000



SERC Capacity Fuel Mix 2010



SPP

SPP anticipates consistent growth in demand and energy consumption over the next ten years. Adequate generation capacity is forecasted to be available over the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins.

Expansion of the existing transmission system to address the reliability and economic needs of the market is a top priority for SPP. SPP is in the process of implementing several initiatives that will result in transmission expansion and better utilization of the existing assets in the footprint.

The existing bulk transmission system is expected to reliably serve the needs of native network load for the short term while incremental system flows from commercial transmission reservations will most likely utilize any remaining transmission capacity.

Demand

SPP, a not-for-profit organization, coordinates reliability functions as an RTO for regional transmission owning members. The SPP transmission system is made up of 13 investor-owned utilities, eight cooperatives, seven municipals, and two state agencies. SPP promotes a member-engaged process of assessing reliability and the necessary expansion of the transmission system to maintain reliability.

Through a working group structure, SPP members are represented on key issues addressing transmission, markets, operations, and policy development. The Transmission Working Group (TWG) collaborates on how best to meet the requirements of NERC reliability standards and SPP regional criteria. The TWG is responsible for evaluations of flowgates, interconnections, short- and long-term reliability and expansion planning for the SPP network.

Interregional coordination is critical to SPP. Joint studies originated under the MRO, MAIN, SPP agreements are utilized to develop an understanding of interregional transfer capability between SPP and its neighbors. SPP is also developing joint operating agreements with Entergy and MISO to better coordinate data essential to the reliability of the grid as a whole.

Resources

The net aggregate capacity reported by SPP members is 45,768 MW with a mix of 45% gas, 43% coal, 3% nuclear, 2% oil, and 7% other. SPP criteria require that members maintain a 12% capacity margin. Expected capacity margins reflected in EIA-411 data are 15.3% in 2006, 14.7% in 2007, and 14.3% in 2008. These numbers correspond closely with the average of 15% capacity margin reported last year. The capacity margins will remain above 12% until 2014 when it drops to 11.6%.

The capacity reported for SPP based on the EIA-411 information does not reflect 9,149 MW of merchant plants that are in the SPP footprint. An important note is that some of these uncommitted resources may not be deliverable to reliably serve customer demand. Additionally, SPP expects around 10,000 MW of nameplate capacity from new merchant generation to be added over the next ten years. The majority of these future additions are wind farms that can only be expected to contribute up to 20% of nameplate rating during summer peak load conditions.

Fuel supply for SPP generating units is expected to be adequate. The SPP region is blanketed with major gas pipelines, which should provide adequate supply for gas-fired plants. Coal-fired plants are expected to have an adequate fuel supply in compliance with SPP criteria requiring sufficient quantities of standby fuel. SPP hydro reservoirs are anticipated to be abundant although the energy output from hydro is not projected to have regional impact given that only 4.5% of SPP capacity is hydro based. No known environmental or regulatory restrictions are expected to impede reliability during the summer months.

Energy

SPP is a summer-peaking region with projected annual peak demand and energy growth rates between 1.3% and 1.5% per year, over the next ten years. These forecast growth rates are comparable to actual experience based on recent history. The SPP actual peak demand and energy consumption for 2004 was 39,986 MW and 191,829 GWh, respectively. Although actual demand depends heavily upon weather conditions and typically includes interruptible loads, forecast net internal demands are based on normal weather conditions and do not include nonfirm loads.

Transmission

SPP held its fourth regional transmission planning summit in Dallas on June 1, 2005, with about 100 participants. SPP's planning process currently involves an 18-month cycle with an initial reliability assessment, followed up with a commercial/market-based assessment. SPP staff presented the recommended reliability projects for the regional expansion plan. SPP has identified an estimated $552,000,000 in reliability projects, which will be needed in 2004–2010. Almost half of the total project costs are associated with new transmission lines. The expected transmission expansions of regional significance include:

- Peculiar 345/161-kV transformer in summer 2005 (Kansas);
- McDowell Creek 230/115-kV transformer in winter 2005 (Kansas);
- Paola 345/138-kV transformer in summer 2008 (Kansas);
- Seven Rivers-Pecos-Potash Junction 230-kV line in summer 2008 (New Mexico);
- Lubbock South 230/115-kV transformer in summer 2009 (Texas);
- Nichols 230/115-kV transformer in winter 2010 (Texas); and
- Northwest Arkansas 345-kV and 161-kV expansion in 2007 and 2010.

SPP has completed the reliability portion of the SPP RTO expansion plan. Phase II of the SPP RTO expansion plan will address potential transmission projects that may be justified based on market factors. SPP will finalize the results of the June 1 summit and publish the final SPP RTO expansion plan by September 1, 2005.

In April 2005, FERC published its order ER05-109-000 conditionally approving the SPP Transmission Pricing Proposal, i.e., cost allocation and cost recovery provisions. The new attachment Z of the SPP OATT provides the necessary mechanism for recovering costs for transmission upgrades identified in the tariff assessment processes. These tariff provisions should address long-standing issues regarding uncertainty of cost recovery associated with transmission upgrades and facilitate the timely expansion of necessary transmission capacity within and around the SPP footprint.

Operations

SPP does not anticipate any operating problems during the 2005–2014 assessment period. SPP has operated a security center since 1997 and is the reliability coordinator for the SPP region. The security center provides the exchange of near real-time operating information and around-the-clock reliability coordination.

SPP implements operating procedures required of a NERC reliability coordinator under the NERC reliability standards. SPP coordinates maintenance outage schedules of the generation and transmission facilities within the region and has approval authority over critical transmission facilities. Daily and next-day security analyses are performed to help members recognize heavy line loading that is expected to occur.

Additionally, real-time contingency analysis is performed every five minutes. When heavy line loading occurs in real time or is expected to occur, NERC TLR procedures are implemented 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 subfunction of the regional operating reserve criteria requirements in which regional participation ensures necessary capacity reserves are available on a daily basis for unexpected loss of generation. The automatic reserve-sharing program meets NERC operating policy.

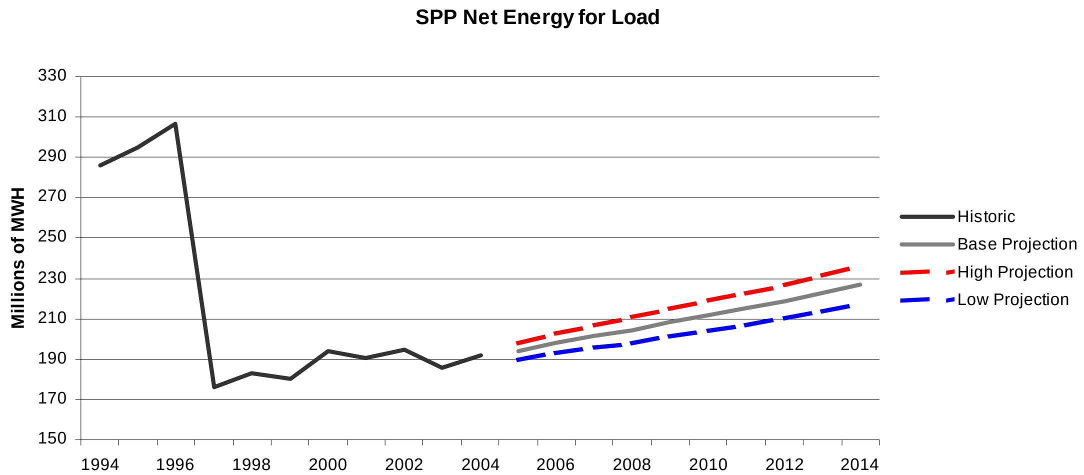
Assessment Process

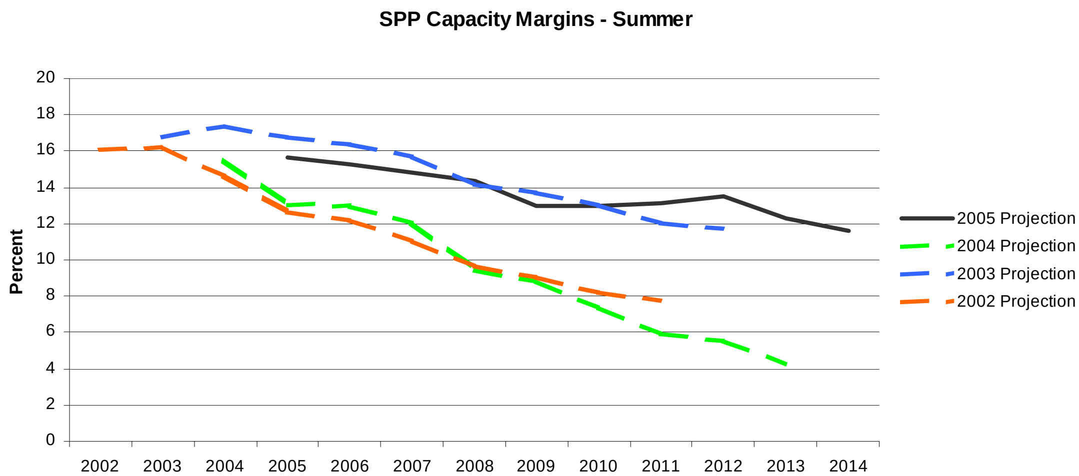
SPP continues to assess the general reliability of the transmission network for the one-to-five year time frames in accordance with NERC reliability standards. The SPP transmission owners have provided mitigation plans where examination of the power transmission network has identified base case and/or (n-1) conditions producing regional violations of reliability criteria. A similar assessment will be performed for the six-to-ten year reliability assessment that is scheduled for completion in October.

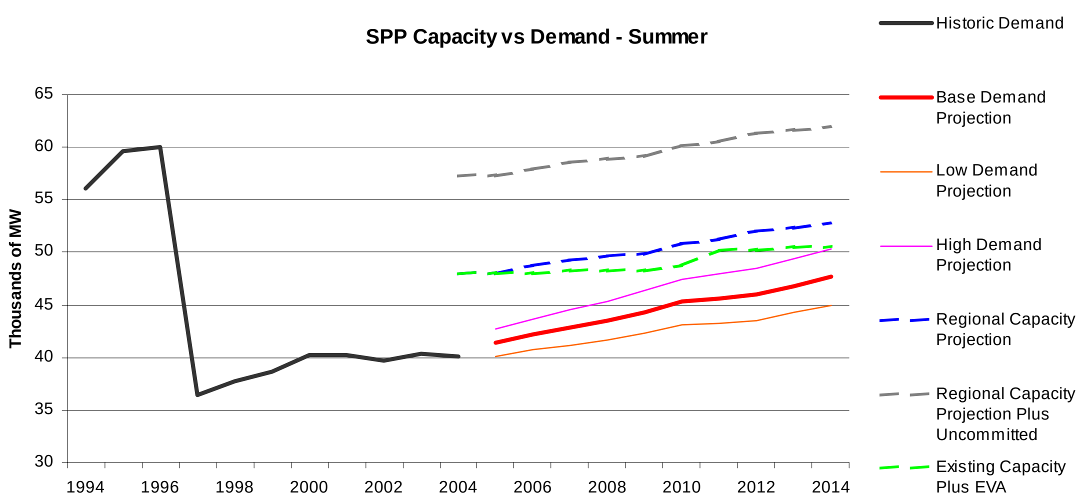
SPP continues to work with neighboring entities to implement effective seams agreements to facilitate coordinated operations and planning.

SPP, a FERC-approved RTO, currently consists of 45 members, serves more than 4 million customers and covers a geographic area of 400,000 square miles containing a population of more than 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 13 investor-owned utilities, seven municipal systems, eight generation and transmission cooperatives, two state authorities and one federal government agency, three IPPs, and 12 power marketers. SPP has more than 350 electric industry employees on various organizational groups that bring together industry-wide expertise to deal with tough reliability and equity issues. An administrative and technical staff of about 150 persons facilitates the organization's activities and services.

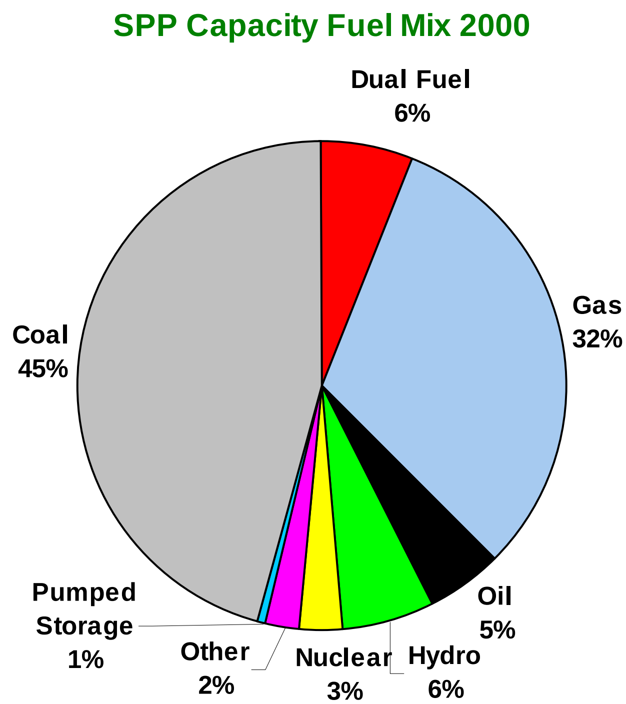
SPP Capacity and Demand

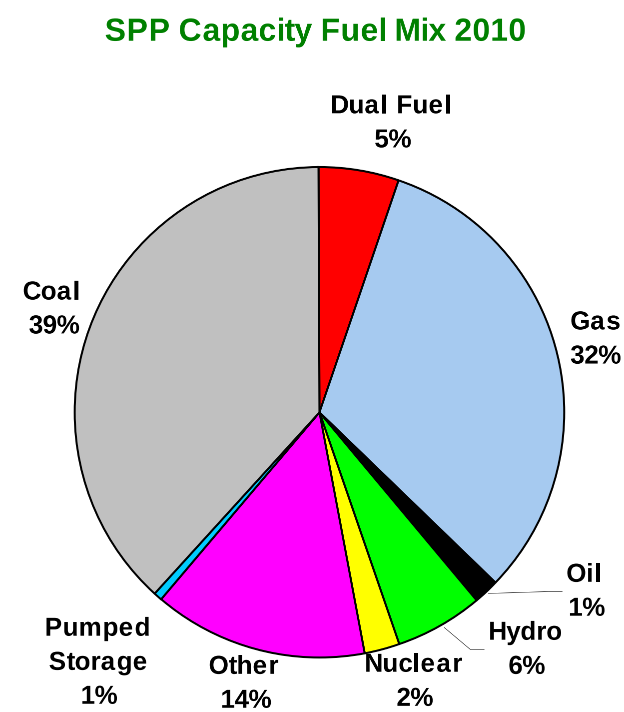






In 1997, former SPP members, Associated Electric Cooperative, Inc., Entergy Corporation, and Cajun Electric Power Cooperative began reporting in SERC. All post-1996 statistics stated herein are based on this change.


SPP Capacity Fuel Mix 2000
Dual Fuel 6%
Gas 32%
Oil 5%
Hydro 6%
Nuclear 3%
Other 2%
Pumped Storage 1%
Coal 45%


SPP Capacity Fuel Mix 2010
Dual Fuel 5%
Gas 32%
Oil 1%
Hydro 6%
Nuclear 2%
Other 14%
Pumped Storage 1%
Coal 39%

WECC

WECC is spread over a wide geographic area with significant distances between load and generation areas. The northern portion of the region is winter peaking and the southern portion of the region is summer peaking. While transmission constraints are a significant factor affecting economic grid operation in the region, 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 25,155 MW of net new generation, which is slightly more than the net planned capacity additions of 22,929 MW reported last year for the 2004–2013 time period. Generation increased by about 3,600 MW in 2004.

Despite a slight increase in proposed new generation during the past year, reported generating capacity additions in the region may not be sufficient to reliably supply the forecast firm peak demand and energy requirements throughout the assessment period. Transmission capacity is expected to be adequate to effectively supply firm customer demand and firm transmission requirements but may not be sufficient to eliminate all inter- and intra-region constraints. Plans have been announced for 5,105 miles of 230-, 345-, and 500-kV transmission line construction and upgrades during the 2005–2014 period.

The reported capacity margin assumes average weather conditions. WECC covers a large geographic area and experiences considerable weather diversity. Under normal weather conditions, this weather diversity allows an area experiencing extreme weather to call on neighboring areas for emergency support. However, a widespread heat wave may result in multiple areas experiencing simultaneous high peak demands, diminishing emergency support capability. Should this occur, portions of the region may need to take actions such as voluntary demand reductions to ensure that adequate operating reserves are maintained.

Demand

Due to cooler than normal temperatures throughout portions of WECC in 2004, projected peak demands are expected to increase by 3.6% from 141,100 MW in 2004 to 146,246 MW in 2005. Thereafter, peak demands are expected to increase by about 2.4% per year compared with 2.2% projected last year for the 2004–2013 time period. It should be noted that capacity margins are measured against firm peak demand, not total peak demand. Demand response and interruptible loads are about 2,470 MW, with about 1,810 MW of the 2,470 MW in California.

Resources

The planned construction of 25,155 MW of net new generation is composed of 9,952 MW of plants under construction and 15,203 MW of plants planned, but not presently being built. If the 3,642 MW of planned retirements and other de-rates occur as scheduled and if no plants are built beyond those already under construction, WECC's capacity margin would drop below 12% by the summer of 2012. Since many load-serving entities plan on maintaining installed reserves of more than 12%, construction of a significant portion of the 15,203 MW of resources not presently under construction is expected to occur prior to 2012.

Transmission

Transmission facilities are planned in accordance with NERC reliability standards and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each system's operation on others and recommend that each system provide sufficient transmission capability to serve its customers, to accommodate planned inter-area power transfers, and to meet its transmission obligation to others.

Transmission rated at 230-kV and above increased by about 700 miles in 2004. Transmission facility additions reported for the 2005–2014 period include 1,986 miles of 230-kV lines, 813 miles of 345-kV lines, and 2,306 miles of 500-kV lines. The transmission system is expected to be adequate to supply firm customer demand and firm transmission requirements throughout the 2005–2014 period.

Operations

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

Assessment Process

Each year, WECC prepares a transmission study report that provides an ongoing reliability-security assessment of the WECC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to NERC reliability standards and 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.

The WECC region has established a process it uses 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. Balancing authorities are reviewed once every three years. Both NERC and FERC personnel are participating in the WECC reviews.
- *Annual Study Report*
  In accordance with WECC policy, the system shall not be operated under system conditions that exceed conditions that have been studied. Security assessment is 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 WECC is expected to be adequate throughout the ten-year period.

Subregions

Northwest Power Pool Area

The Northwest Power Pool (NWPP) 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 2005–2014 assessment period, winter peak demand and annual energy requirements are projected to grow at annual compound rates of 1.7 and 1.9%, respectively. Because capacity margins for this winter-peaking area range between 23.7 and 28.6% for the next ten years, the ability to meet peak demand is expected to be adequate for the next ten years.

NWPP planning is conducted by subarea. Idaho, northern 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. In 2001, the Northwest experienced its second lowest coordinated Columbia River system volume runoff since record keeping began, with reservoirs refilling to just 71% of capacity, the lowest levels in almost a decade. Since 2001, the reservoir refill has ranged between 87 and 92% of capacity.

The reservoirs are managed to address all the competing requirements including but not limited to the following: current electric power generation, future (winter) electric power generation, flood control, fish and wildlife requirements, special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs. In addition to managing the competing requirements, other available generating resources, market conditions, and load requirements are considered and incorporated into the decision for refilling the reservoirs. Any time precipitation levels are below normal, balancing these interests becomes even more difficult.

A ten-year agreement was reached in 2000 among parties involved in operation of the Columbia River Basin pertaining to river operations. However, this agreement is subject to three-, five-, and eight-year performance checks and reopening by the parties. The net effect 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.

Proposed NWPP Projects > 50 Miles	Status	Date
Cordell, AB to Metiskow, AB 240-kV line	Planning	2005
Pincer Creek, AB to Lethbridge, AB 240-kV line	Planning	2006
Keephills-Genesee-Ellerslie, AB 500-kV line	Planning	2006
Ellensburg, WA to Sunnyside, WA 500-kV line	Planning	2006
Benewah, ID to Shawnee, WA 230-kV line	Planning	2006
Montana-Alberta 230-kV merchant line	Planning	2006
American Falls, ID to Eden, ID 230-kV line	Planning	2007
Vancouver Island-Arnott 230-kV line	Planning	2008
Keephills, AB to Langdon, AB 500-kV line	Planning	2009
Cranbrook, BC to Invermere, BC 230-kV line	Planning	2011
Mona, UT to Salt Lake, UT 345-kV line	Planning	2011
Nicola, BC to Meridian, BC 500-kV line	Planning	2013
Southwest Intertie Project (ID-NV 520-mile tie)	Planning	2013

In view of the longer time required for transmission permitting and construction, NWPP recognizes 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 about 986 miles of 500-kV transmission lines.

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 under double-circuit simultaneous outage conditions, the Northwest depends on an underfrequency load-shedding scheme.

Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during summer peak demand periods. In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase imports, which would reduce reservoir drafts and aid reservoir filling.

Generation in the province of Alberta, Canada, operates in a fully restructured environment, so resource additions are market driven. Generation additions and demand growth are expected to result in transmission constraints in a number of areas over the course of the assessment period. The impact of most of these constraints is anticipated to be local in nature and will not affect the transmission systems outside of Alberta.

Applications for two major system developments have been filed with the provincial regulatory authority. The first of these is for the development of about 105 kilometers (65 miles) of 240-kV transmission line to accommodate several new wind generation developments in southwest Alberta: this development has an in-service date of 2007. The second application is for the construction of a 500-kV line, about 330 kilometers (200 miles) in length, to strengthen the main north-south transmission grid: this development has a proposed in-service date of 2009 and the application has been approved. In conjunction with this project, an application has been submitted to install 520 Mvar of capacitor banks as an interim measure. The capacitor banks are expected to be in service by the end of 2005. A Calgary area transmission must-run (TMR) ancillary service operation procedure has been updated to address the 240-kV transmission grid loading issues and to ensure that voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta near Calgary and assist in maintaining overall system security. Increased local area demand has reduced the export capability of the Alberta-Saskatchewan dc tie. A planning study is currently under way to analyze the Empress area and the Alberta-Saskatchewan dc tie export capability. The study and recommendations are expected to be completed by December 2005. Applications for additional transmission developments will be filed as required.

The Canadian province of British Columbia relies on hydroelectric generation for 90% of its resources. British Columbia Hydro and Power Authority are addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The definition phase of a new 500-kV line between Nicola and Meridian substations and a 230-kV underwater cable between Arnott substation and Vancouver Island terminal is under way. The new 500-kV line will increase the total transfer capability of the interior to lower mainland area grid and the new 230-kV cable will increase the transfer capability from the lower mainland area to Vancouver Island. These projects have proposed in-service dates of 2013 and 2008, respectively.

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. For the 2005–2014 period, peak demand and annual energy requirements are projected to grow at annual compound rates of 2.5 and 2.3%, respectively. Capacity margins range between 12.8 and 13.4% for the next ten years.

Proposed RMPA Projects > 50 Miles	Status	Date
Lamar, Colorado 210 MW dc tie to SPP	Completed	January 2005
Midway, CO to Denver, CO 345-kV line (initially operated at 230-kV)	Completed	May 2005
Carr Draw-Hartzog-Teckla, WY 230-kV lines	Underway	Late 2005
Walsenburg, CO to Gladstone, NM 230-kV line	Under way	Late 2007
Hughes, WY to Sheridan, WY 230-kV line	Planned	2008
San Luis Valley-Walsenburg, CO 230-kV line	Planned	2009
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	Under way	2009

Due to extended drought, the hydro generation is at low levels along the North Platte River. The low flows could also impact water requirements at steam turbine plants, requiring alternative water supply tactics. WECC expects that water levels in Lake Powell, which is the reservoir for Glen Canyon dam generation, will end the 2005 water year 95 feet below full. This results in a capacity reduction of about 200 MW (17%) due to lower hydraulic head at the plant.

The Western Area Power Administration plans to upgrade several 115-kV transmission lines to 230-kV over the next ten years to increase transfer capabilities and to help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado.

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. For the 2005-2014 period, peak demand and annual energy requirements are projected to grow at annual compound rates of 3.0%. Capacity margins for this summer-peaking area range between 11.7 and 23.8% for the next ten years.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this 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, although an expansion of the Springerville coal-fired plant is under way with one unit under construction and an additional unit scheduled to be built between 2009 and 2012. Frequently, resource acquisitions are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make generation adequacy forecasting problematic for an extended period of time.

In early 2000, several Arizona utilities initiated a regional EHV transmission study to evaluate developing transmission alternatives in the central Arizona area. This study was called the central Arizona transmission system (CATS) study. The study resulted in a coordinated transmission plan and included one jointly owned 500-kV transmission project that was sited in 2004 and a second project that initiated siting in 2004. During 2003 and 2004, the Arizona CATS participants worked with stakeholders from New Mexico, southern Nevada, west Texas, and southern Colorado to expand the coordinated planning effort. The result was the formation of the Southwest Area Transmission (SWAT) planning group. SWAT has five subarea technical groups to assess and address the coordinated planning needs of specific subareas.

Transmission providers from the Arizona-New Mexico-Southern Nevada Power Area are also actively engaged in the Southwest Transmission Expansion Planning (STEP) group along with stakeholders from southern California. The goal of this group is to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, southern Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. Three projects have resulted from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW.

Proposed AZ/NM/SNV Projects > 50 Miles	Status	Date
Harry Allen, NV to Mead 500-kV line	Permitted	2007
Palo Verde-TS5 500-kV line	Permitting	2007
Nogales, AZ to Sahuarita, AZ 345-kV lines	Planned	2007
Stirling Mt-Northwest-Vista, NV 230-kV line	Planned	2007
Palo Verde to Southeast Valley (Phoenix area)	3 parts	2011
A. Palo Verde to Pinal West 500-kV line	Permitted	2007
B. Pinal West to Santa Rosa 500-kV line	Permitting	2007
C. Santa Rosa to Browning 500-kV line	Permitting	2011
TS5-Raceway 500-kV line	Planning	2010
Shiprock, NM to Marketplace, NV 500-kV line	Permitted	2010
Centennial II (Las Vegas, NV area) 500-kV line	Planning	2012
Pinal West-Tortolita, AZ 500-kV line	Planning	2012
Palo Verde-North Gila 500-kV line	Planning	2012
Northern to central New Mexico 345-kV generation outlet lines	Planning	2013
Greenlee-Springerville, AZ #2 345-kV line	Planning	2014
Tucson, AZ area 345-kV reinforcements	Planning	2014

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 2.4 and 2.6%, respectively, from 2005 to 2014. Projected capacity margins range between 11.7 and 13.0% for the next ten years.

Uncertainty surrounding future resources in California has raised questions regarding future projections of generating capacity, energy production by generators, and effects of customer energy efficiency and other demand-side management programs. Three years ago, for example, more than 45,000 MW of planned resource additions were reported for the area for the 2002–2011 ten-year period. Two years ago, the reported additions had declined to 7,100 MW over the 2003–2012 period. Last year the reported additions declined further, to 5,541 MW. This year's assessment reports a slight increase, to 6,783 MW for the 2005–2014 period. It is estimated that the subregion may need up to an additional 10,700 MW of capacity to achieve a 15% planning reserve margin for the 2010–2014 period. While a portion of that capacity may be available from other subregions, most of it will have to come from new plants that are not presently identified.

State energy agencies in California are proceeding on several fronts to address concerns regarding electric power adequacy. For example, the California Energy Commission has prepared a *2004 Integrated Energy Policy Report Update* that calls for the state to move aggressively to bring new resources into service and to step up efforts to achieve goals already established for demand-response programs. The report also calls for a comprehensive transmission planning process to address a systematic under investment in transmission and consequent internal congestion conditions. The California Energy Commission is working on its 2005 Integrated Energy Policy Report, which is scheduled for completion and transmittal to the Governor and California Legislature in November 2005. This new report will include a five-year outlook of California electricity supply and demand, as well as summaries of the resource plans of the California load-serving entities. Two of the key findings, thus far, are that: 1) adequate reserve margins can be maintained through 2010 if "high-risk" plant retirements are delayed, if demand is reduced, or if more resources are added, and 2) projected additions to supply can keep pace with demand growth forecasts between 2006 and 2010, if existing capacity is maintained.

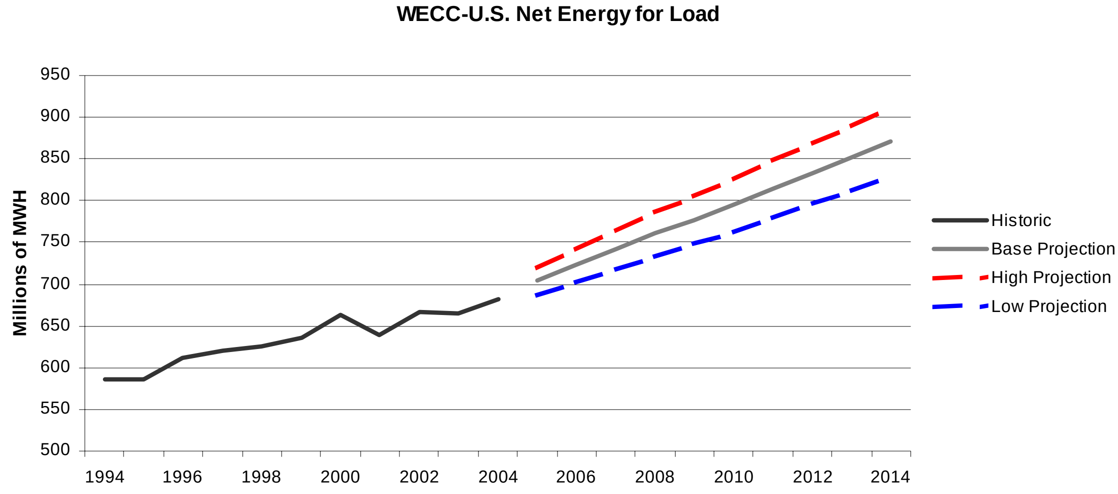
The state is implementing a mandatory minimum reserves requirement to achieve resource adequacy and is looking to new customer electricity metering equipment as a key component to achieving demand-response goals. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

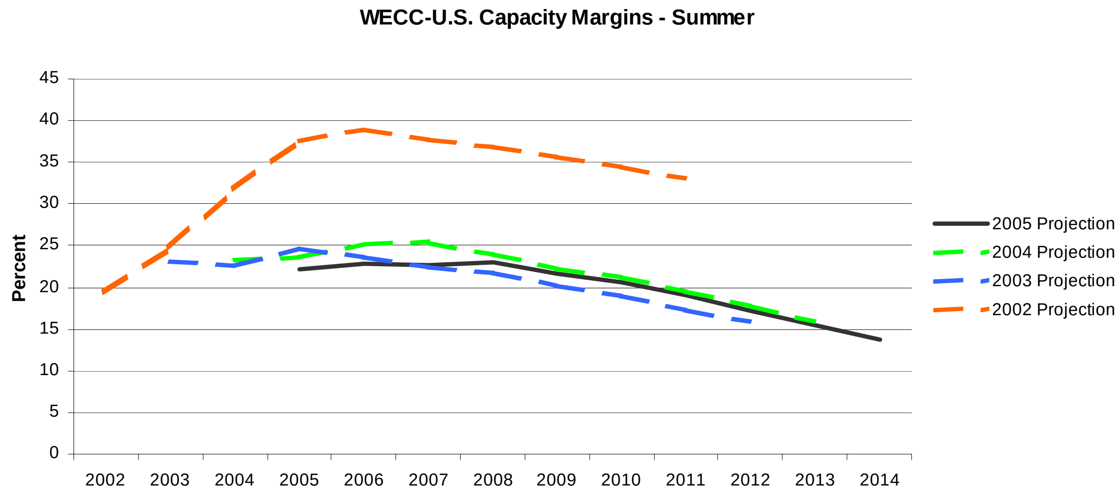
Since the addition of several generating plants in Arizona, southern Nevada, and Mexico, the bulk transmission system into southern California has become increasingly congested due to the desire to increase imports from the surrounding areas. Special protection schemes have been implemented for new generation 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 Mexico's Comision Federal de Electricidad (CFE) and Arizona. The California ISO 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 from new Southwest generation.

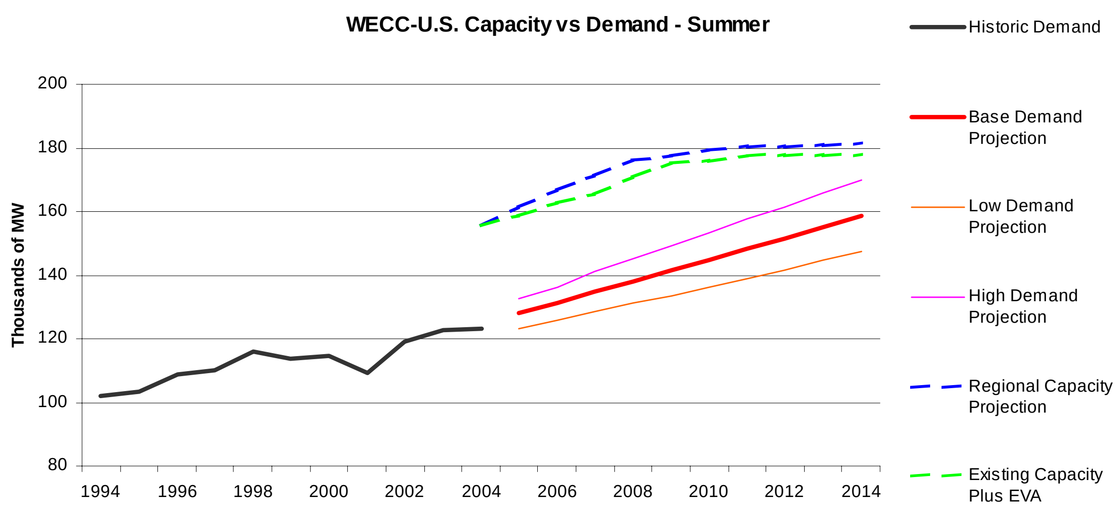
Proposed CA/MX Projects > 50 Miles	**Status**	**Date**
La Herrandura Project, MX 230-kV lines	Planning	2005
Palo Verde-Devers #2 500-kV line	Permitting	2009
New Vincent-Mira Loma 500-kV line	Planning	2011
Imperial Valley-San Diego 500-kV line	Planning	Unknown
Tehachapi Area Transmission – 500-kV	Planning	Unknown

WECC comprises 169 member companies and organizations, and encompasses an area of nearly 1.8 million square miles with about 71 million people. It is the largest and most diverse of the ten NERC regional reliability councils. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources.

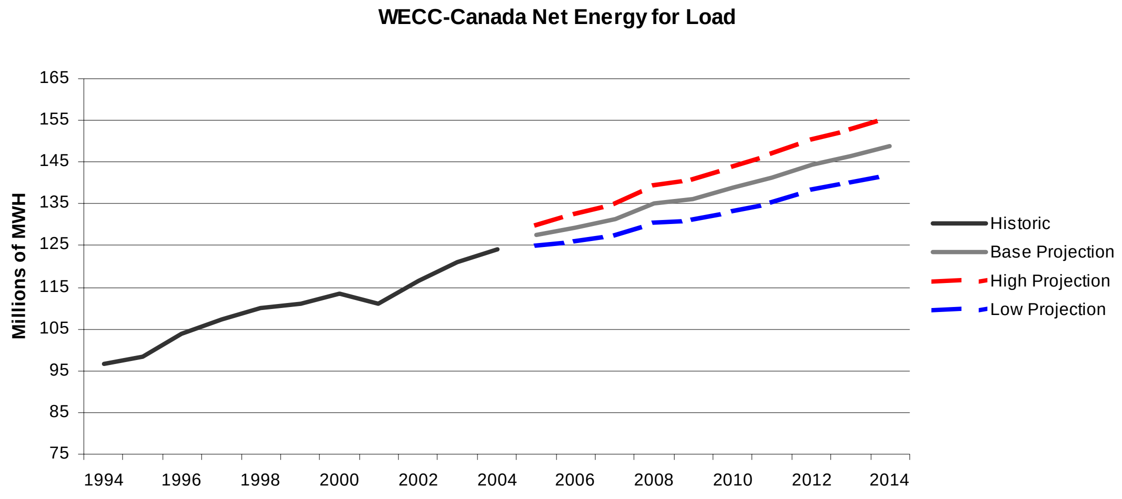
WECC-U.S. Capacity and Demand

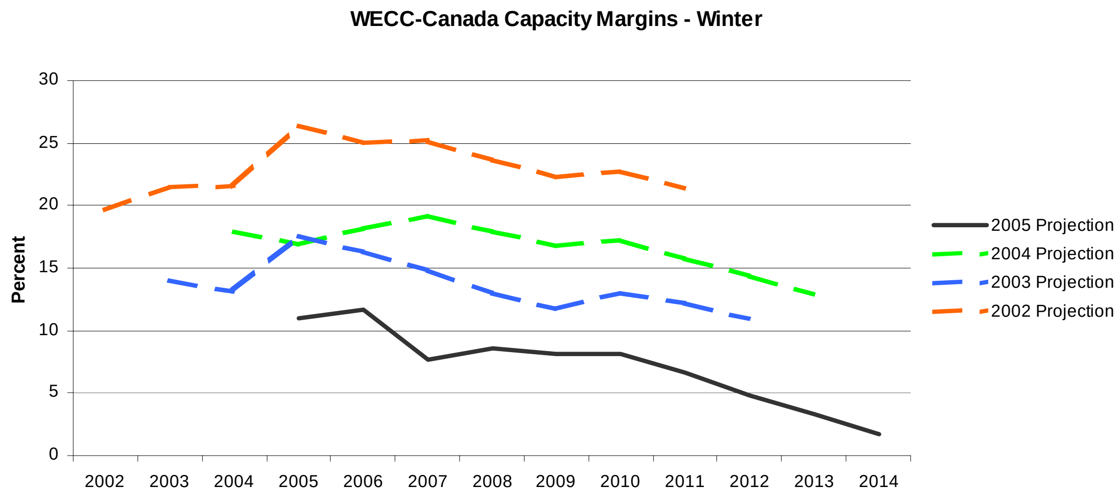


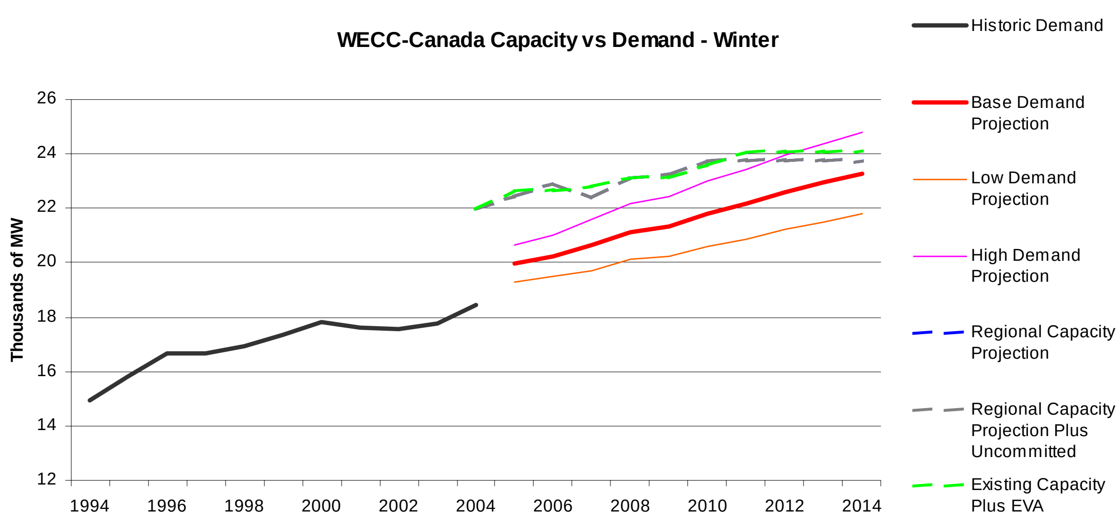




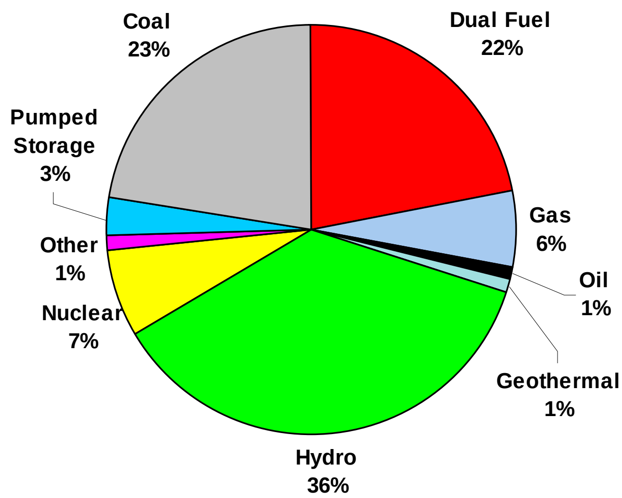
WECC-Canada Capacity and Demand



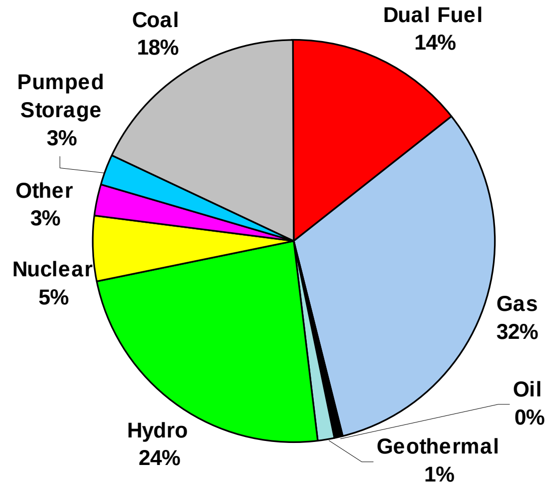




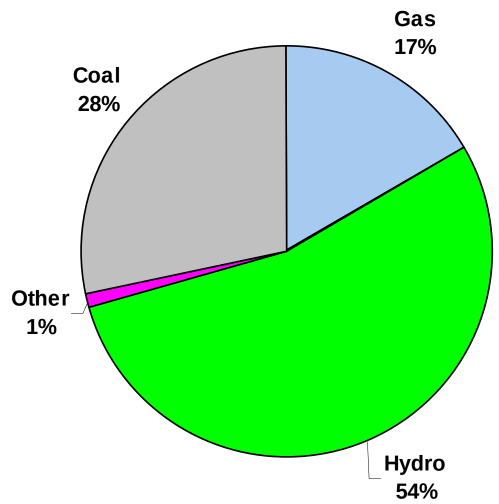
WECC-U.S. Capacity Fuel Mix 2000



WECC-U.S. Capacity Fuel Mix 2010



WECC-Canada Capacity Fuel Mix 2000



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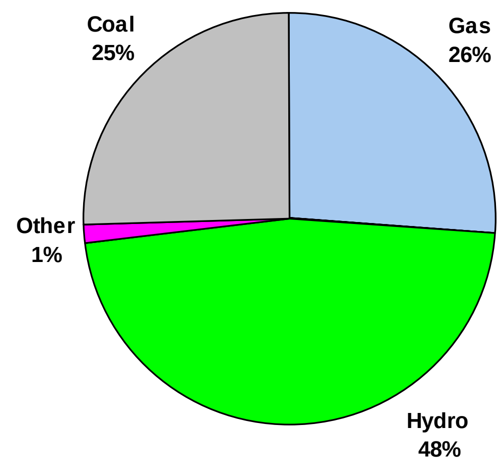


Appendix A

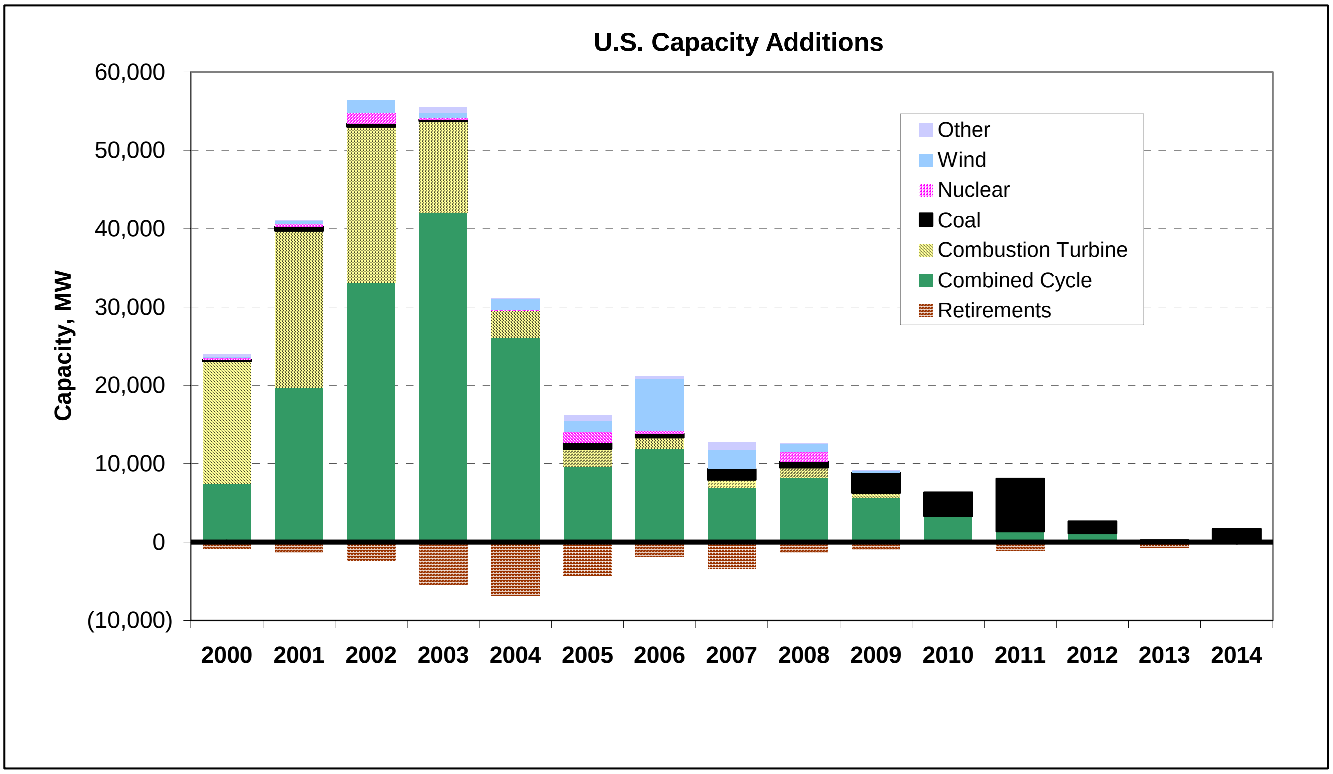
Today's era of differing levels of regulation and deregulation within the power industry make it more difficult to access information on power project development than during the regulated era. To track project development in a consistent and orderly fashion, EVA maintains a database that ranks progress towards completion in one of six categories: in operation (Category 1); under construction (2); advanced development stage (3); early development stage (4); unlikely (5); and withdrawn (6).

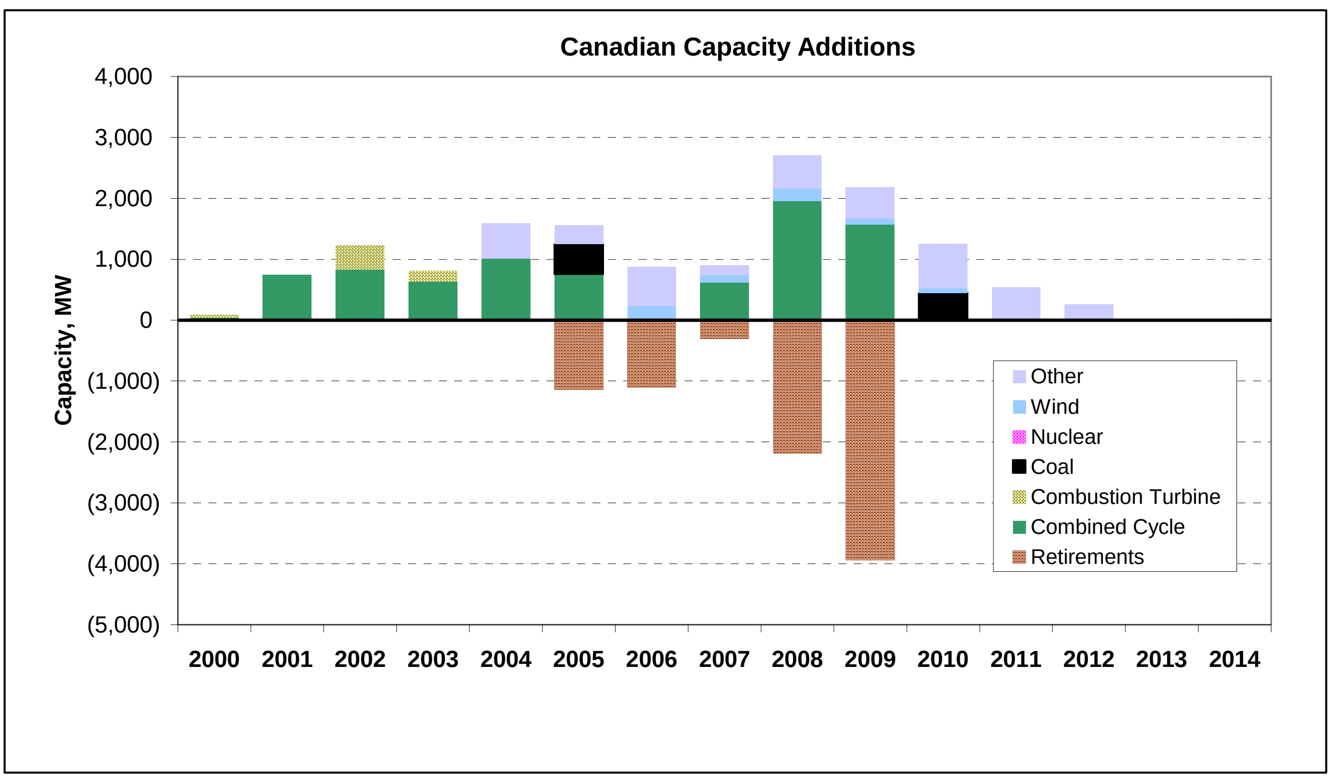
The first two categories and Category 6 are straightforward and easily observable. Categories 3 to 5 each have distinctive qualitative attributes that are related to a particular project's progress through the development phase. A new project often, but not always, starts with public announcements by the developers themselves. At this stage, the project is assigned a Category 4 ranking and retains that ranking, at least for as long as the developer continues to pursue the project actively. Often, at this early development stage public information about the project is lacking.

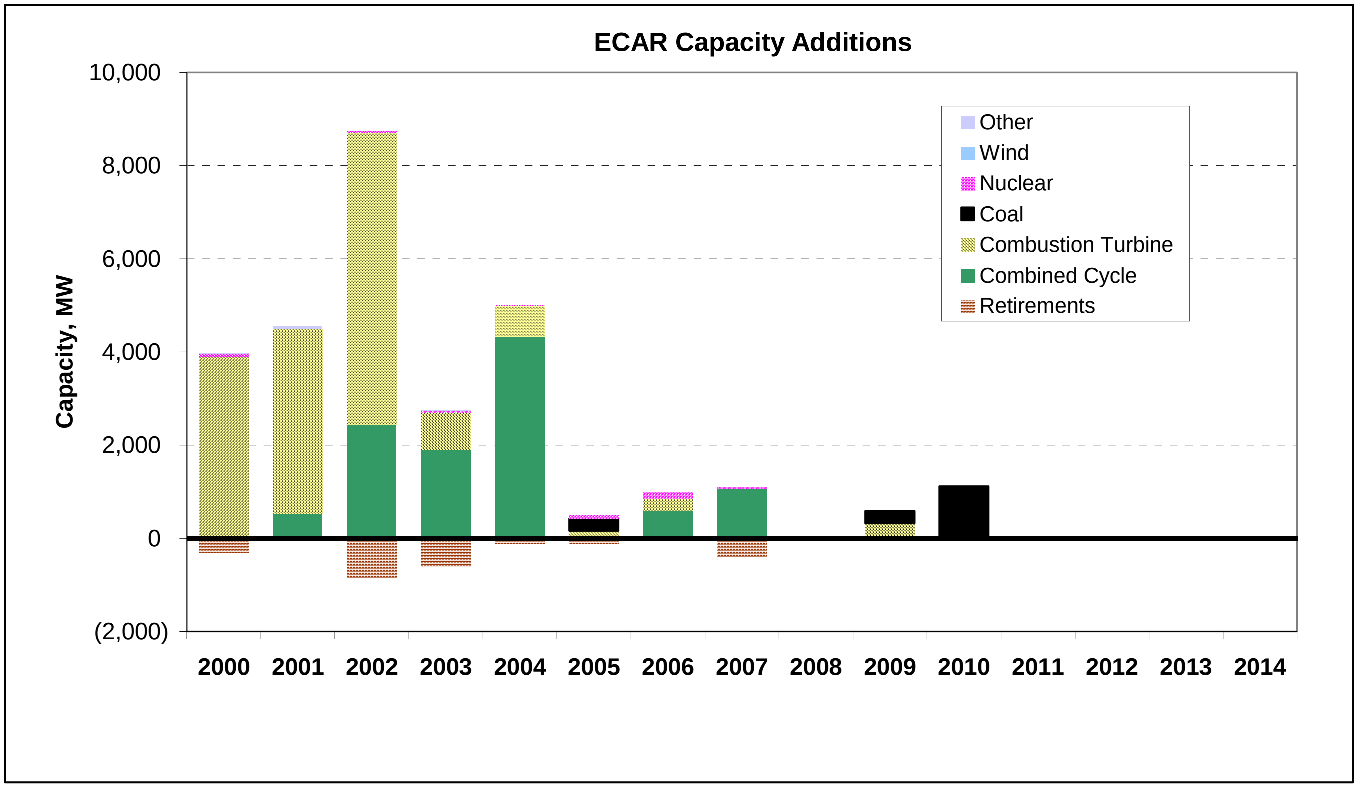
A project is advanced to Category 3 when it has fulfilled most, if not all, of the basic elements necessary to construct the project — for example, financing, permitting, and orders for major equipment. A Category 5 ranking is assigned to projects that have missed targeted milestones or other indicators that point to a lapse in development activity — such as no site identified. Category 6 is assigned when the developer actually withdraws the project.

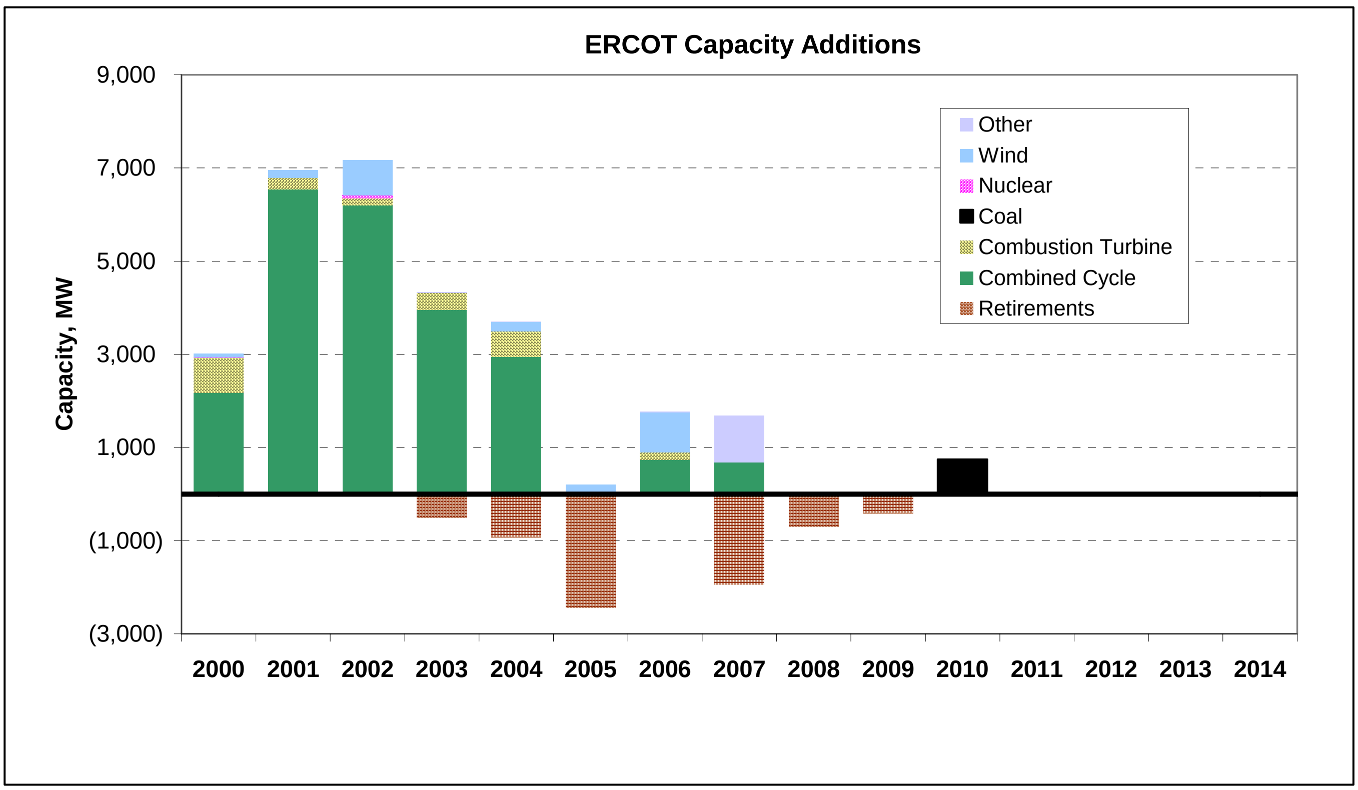
The data shown in the appendix reflects only those projects considered to be under active development (i.e., Categories 1 to 4).

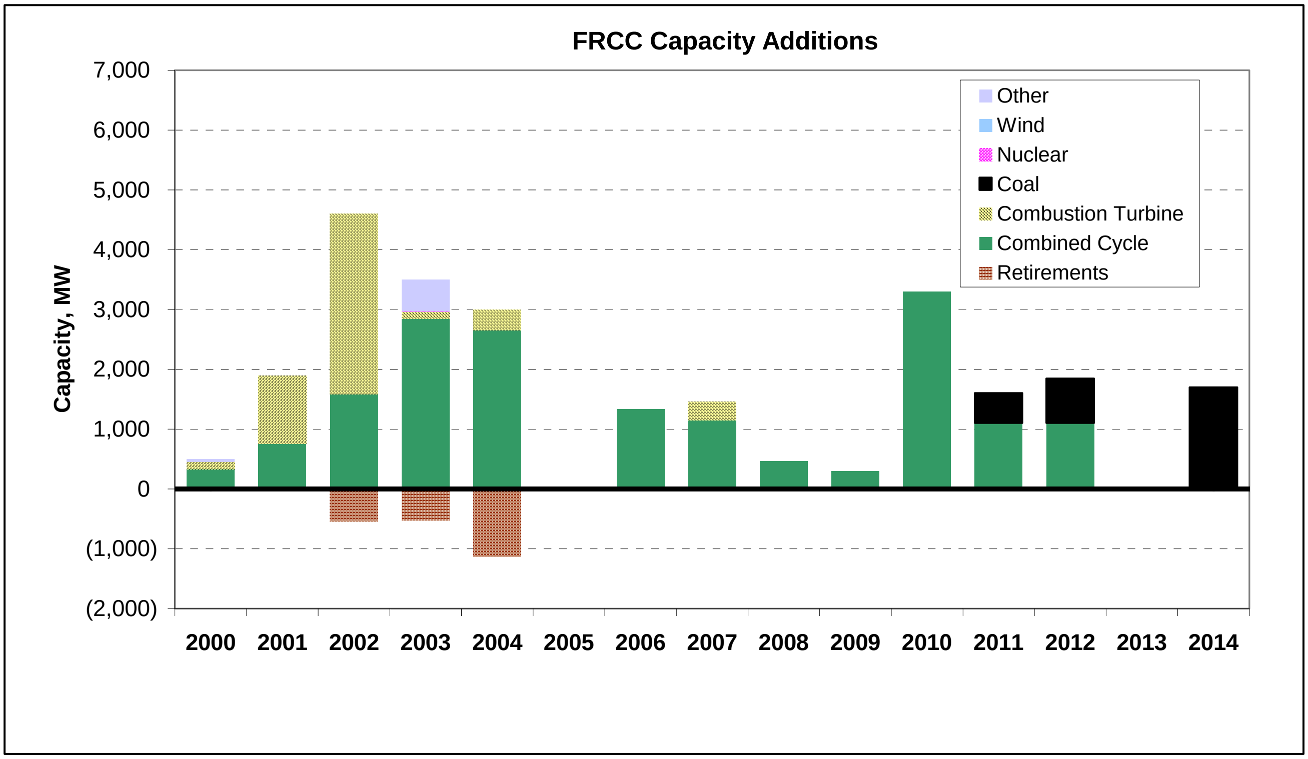
While the intermittent nature of wind generation resources make it difficult to determine the amount of wind generation that would be available to serve load at the time of system peak demand, the bar graphs on the following pages show wind capacity at nameplate ratings. The actual amount of available capacity might be less.

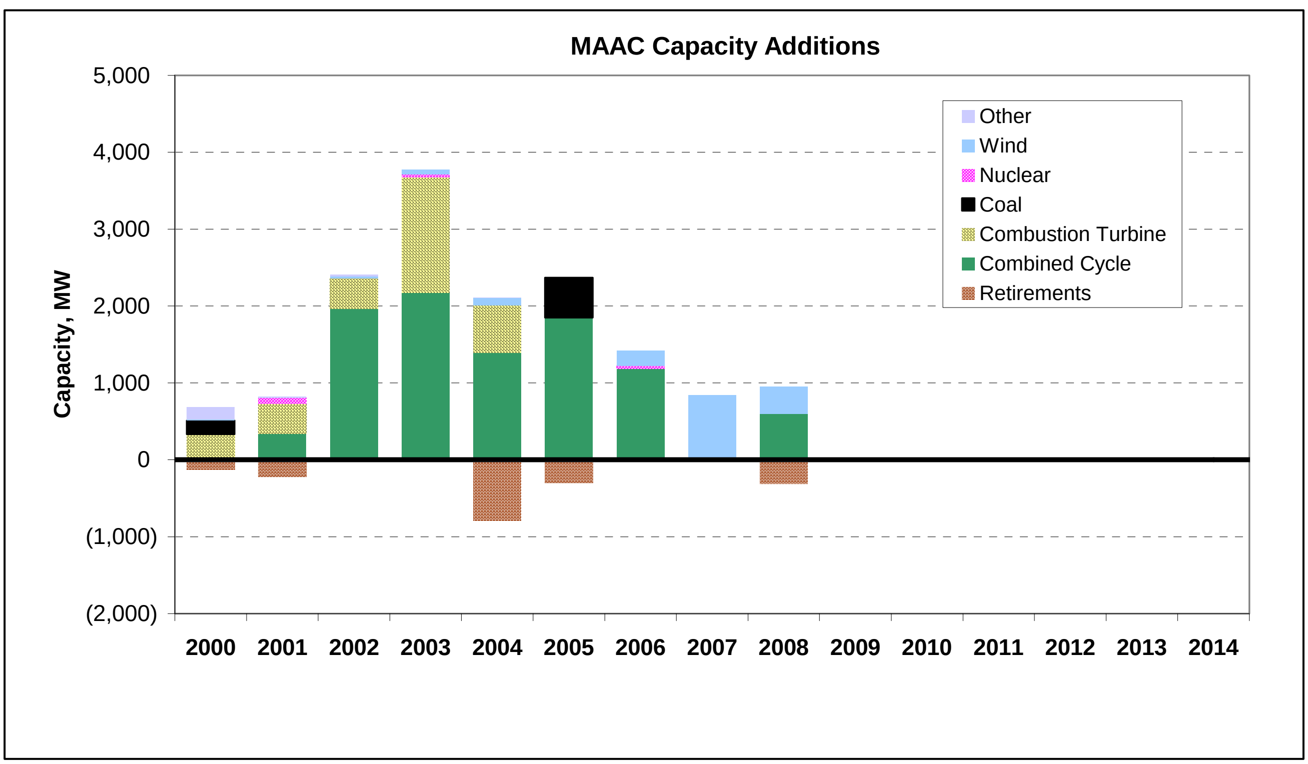

U.S. Capacity Additions
Capacity, MW
60,000
50,000
40,000
30,000
20,000
10,000
0
(10,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

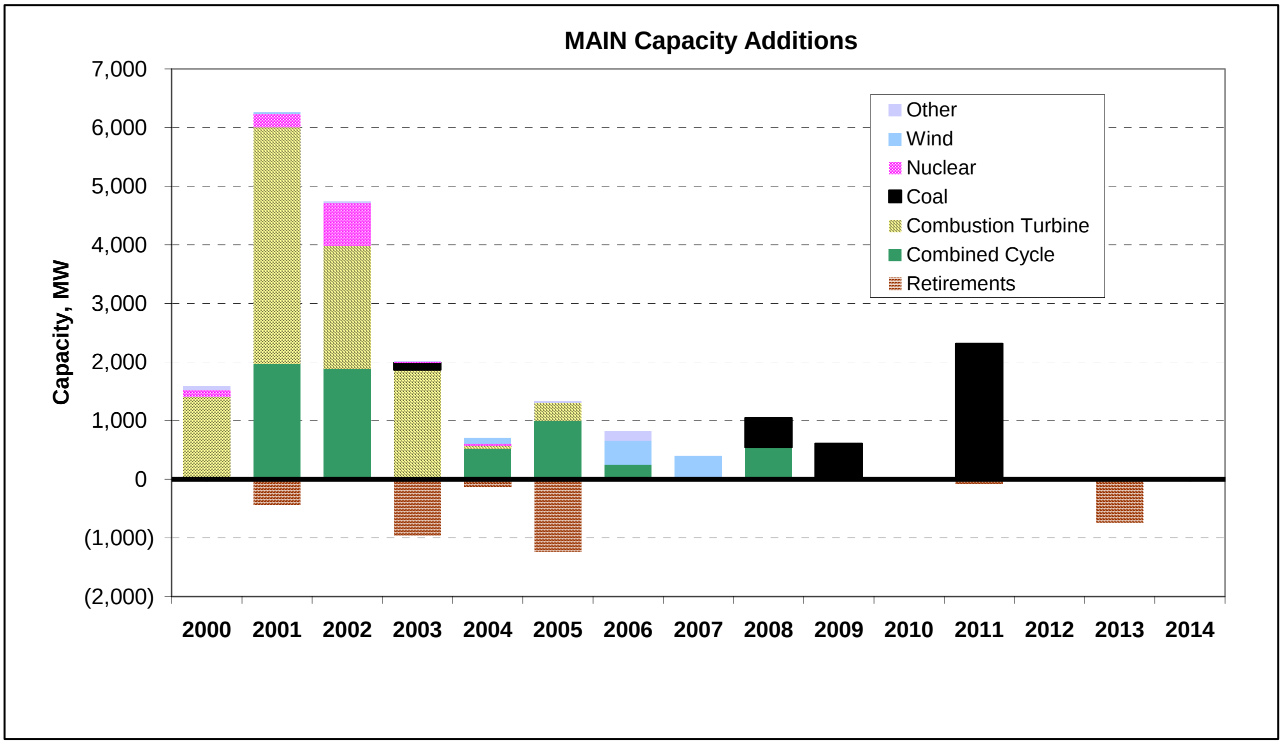

Canadian Capacity Additions
Capacity, MW
4,000
3,000
2,000
1,000
0
(1,000)
(2,000)
(3,000)
(4,000)
(5,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

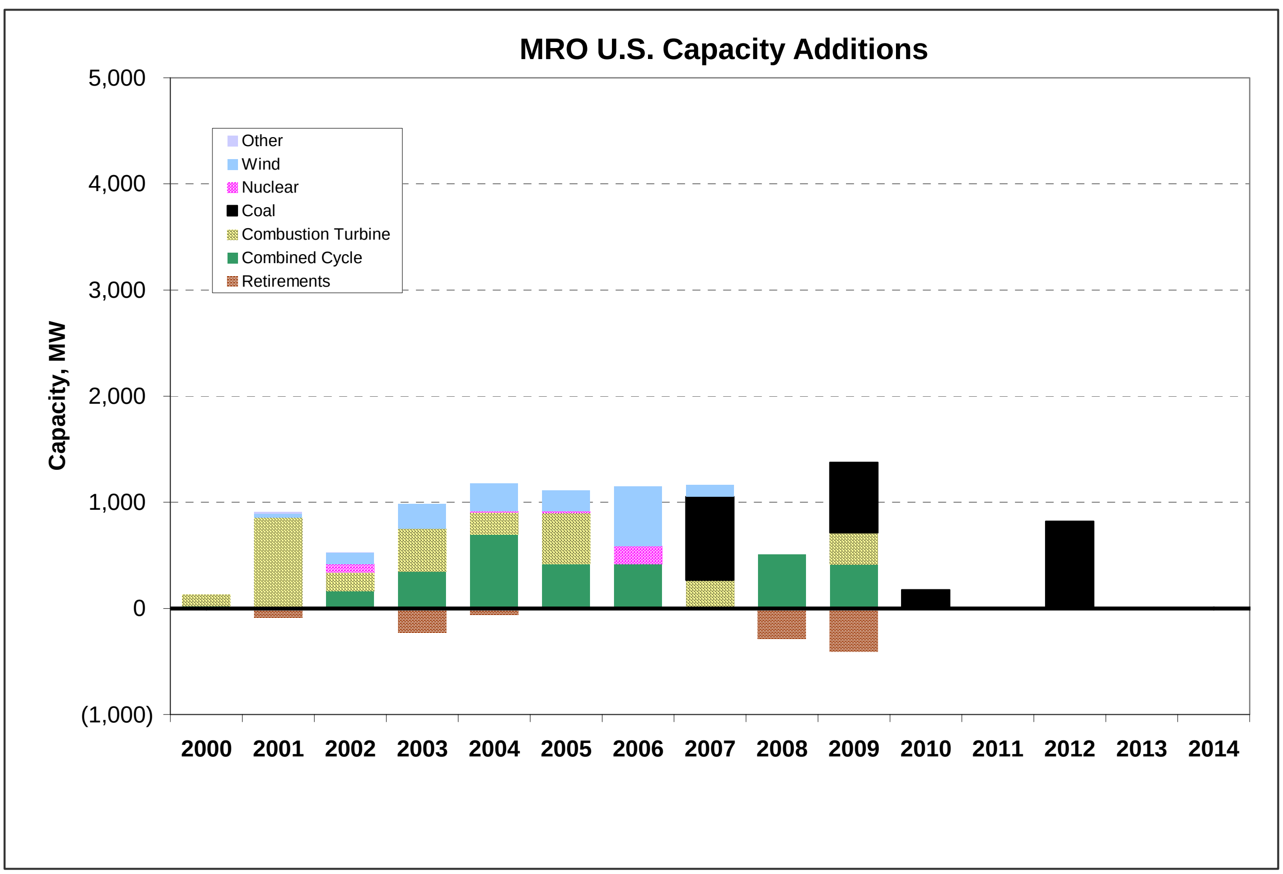

ECAR Capacity Additions
Capacity, MW
10,000
8,000
6,000
4,000
2,000
0
(2,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

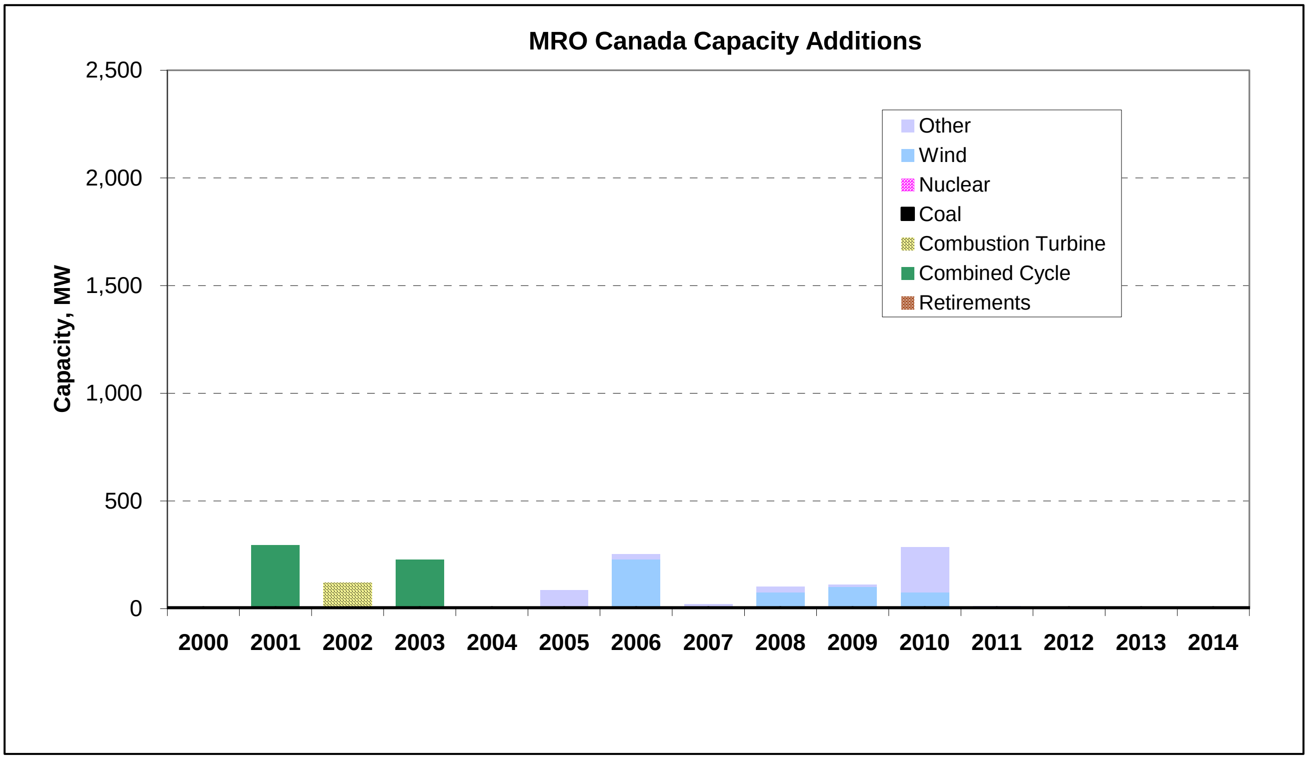

ERCOT Capacity Additions
Capacity, MW
9,000
7,000
5,000
3,000
1,000
(1,000)
(3,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

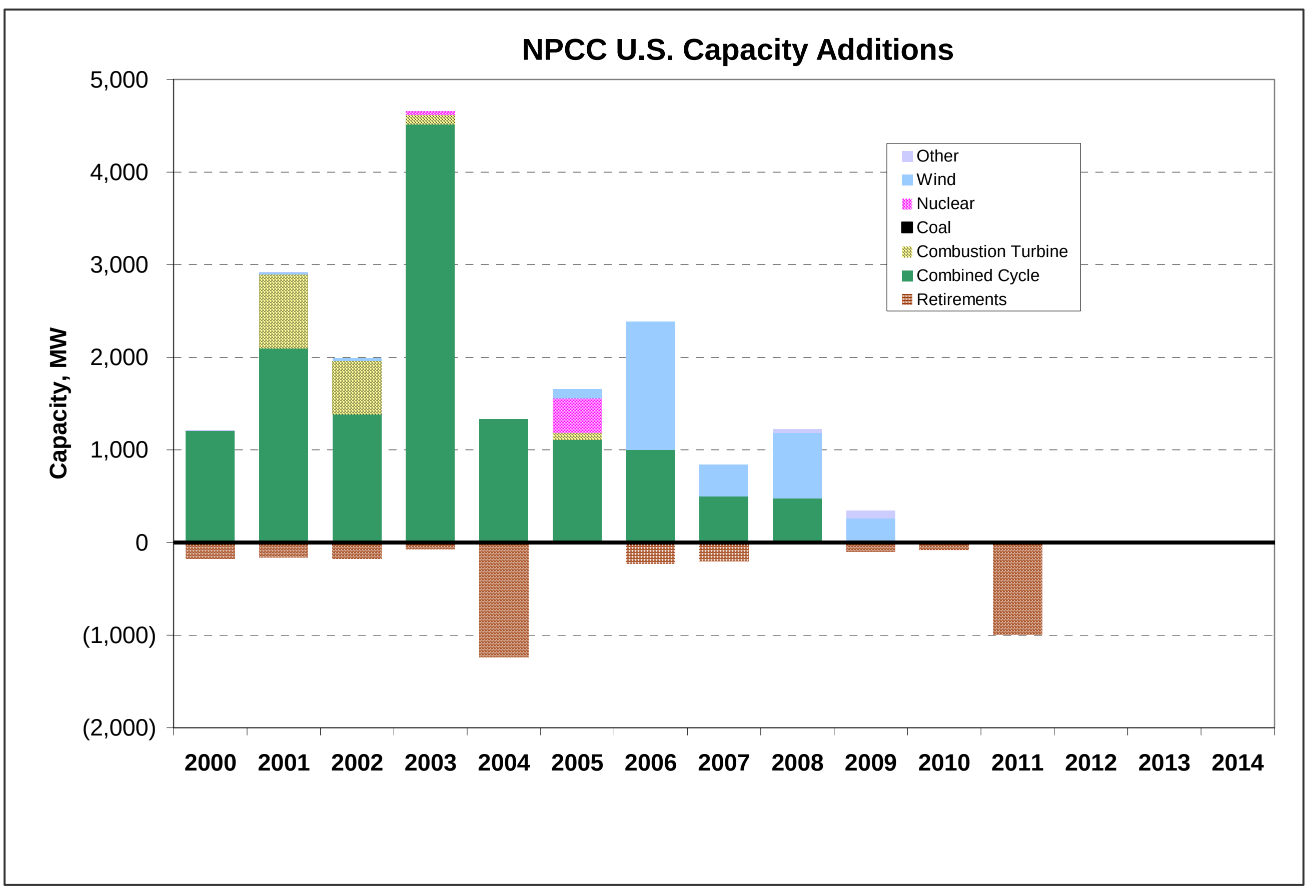

FRCC Capacity Additions
Capacity, MW
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
(1,000)
(2,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

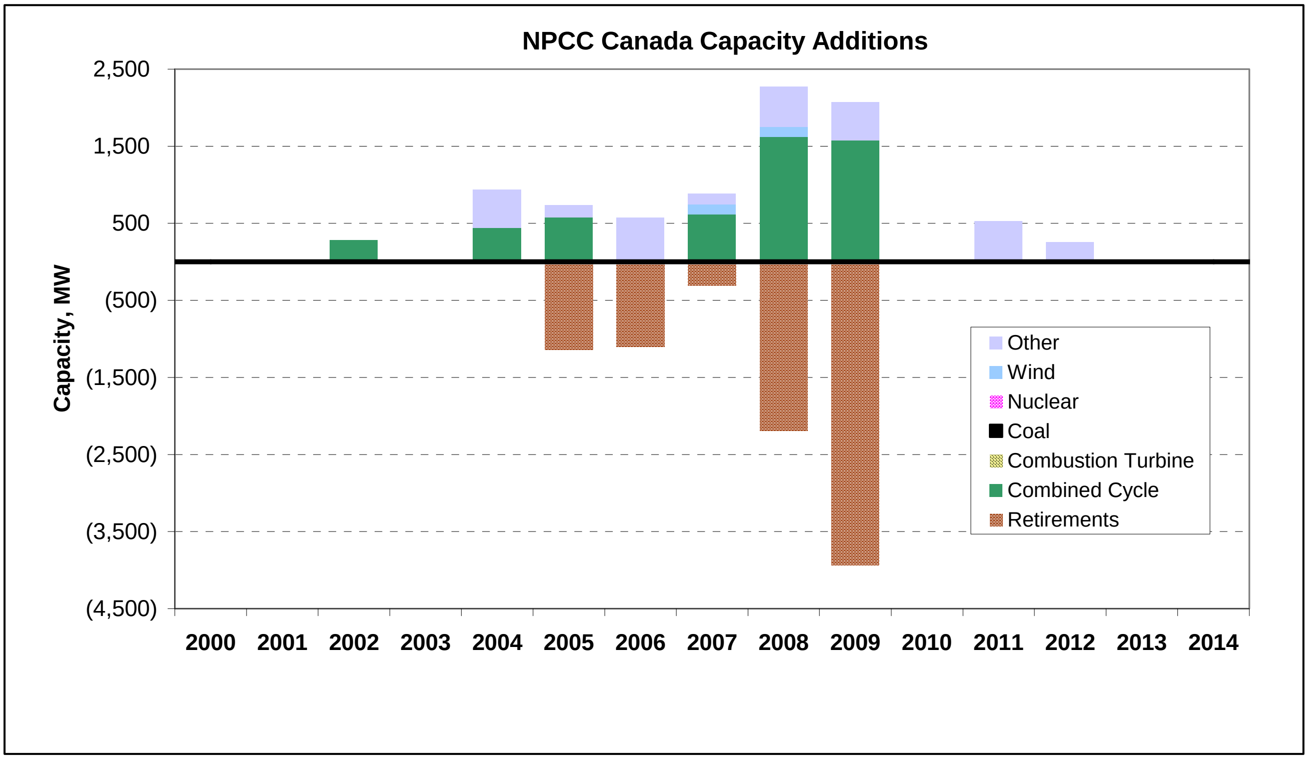

MAAC Capacity Additions
Capacity, MW
5,000
4,000
3,000
2,000
1,000
0
(1,000)
(2,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

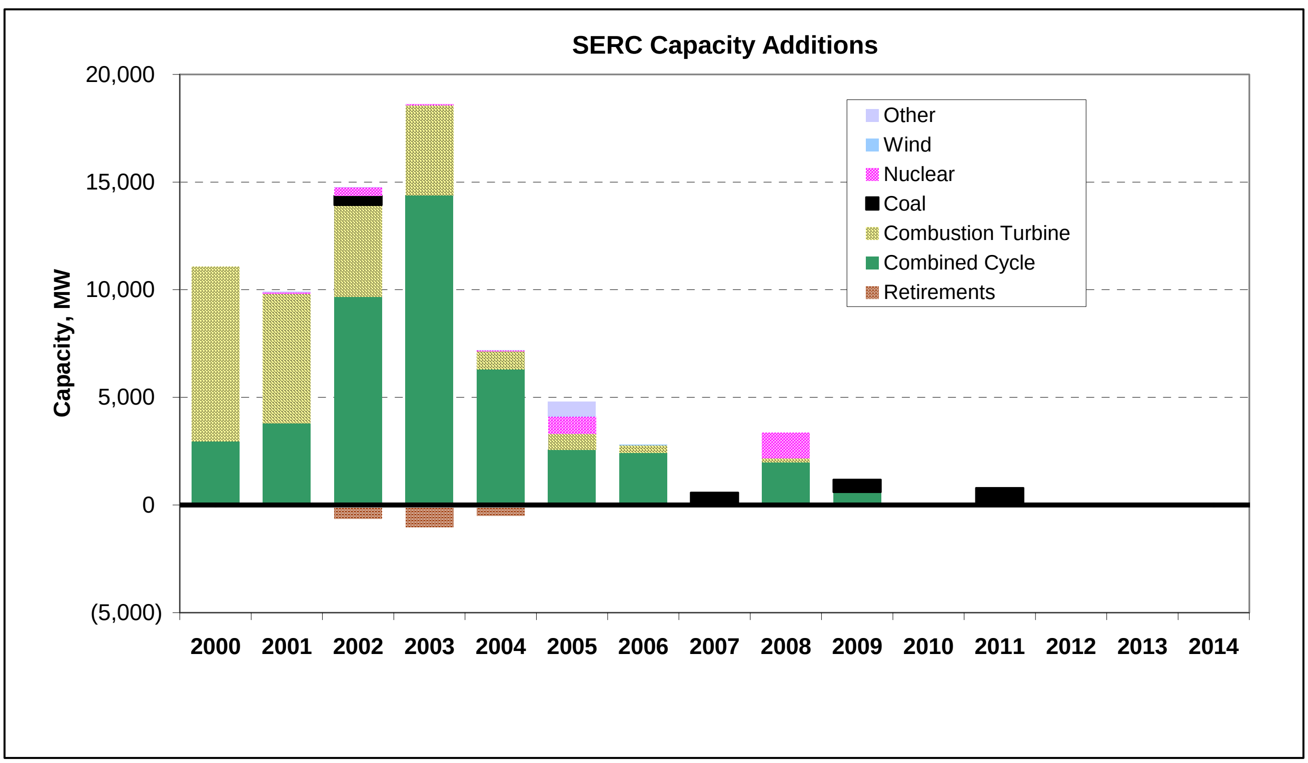

MAIN Capacity Additions
Capacity, MW
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
(1,000)
(2,000)
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

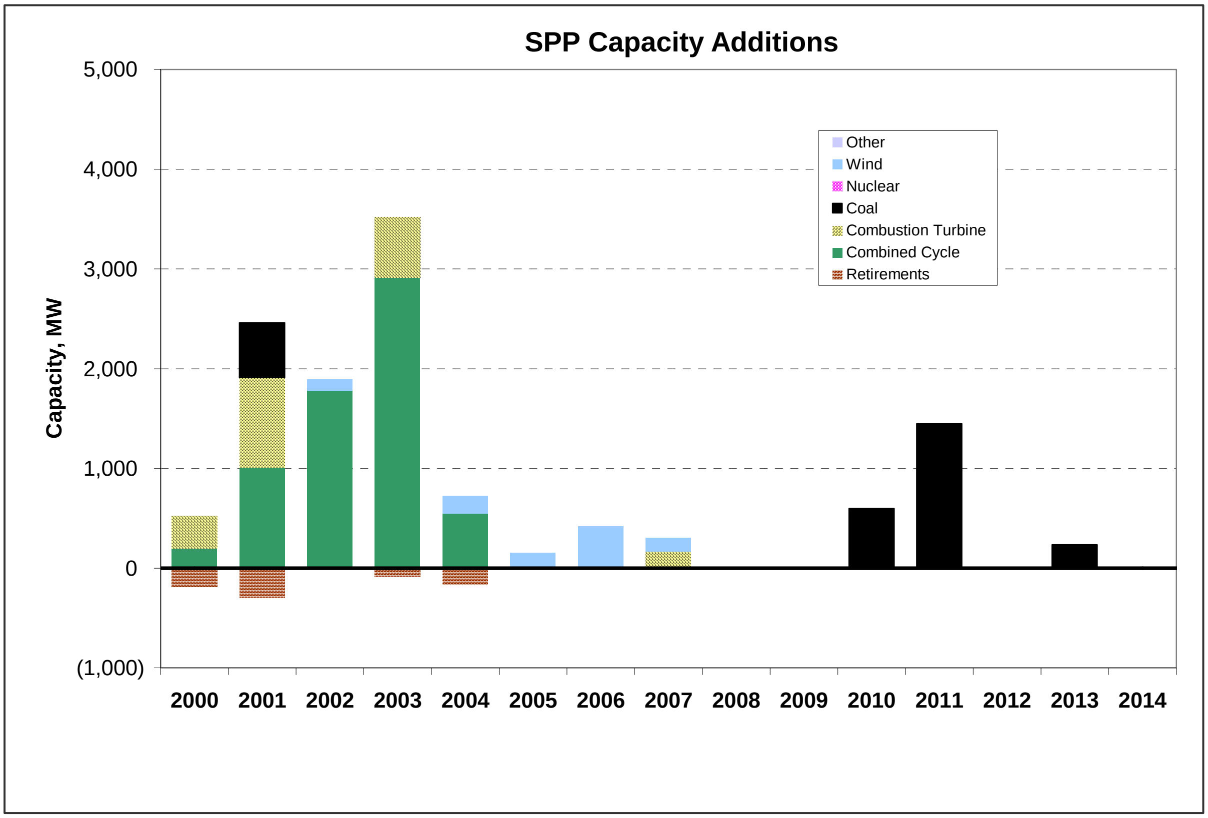

MRO U.S. Capacity Additions
Capacity, MW
5,000
4,000
3,000
2,000
1,000
0
(1,000)
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

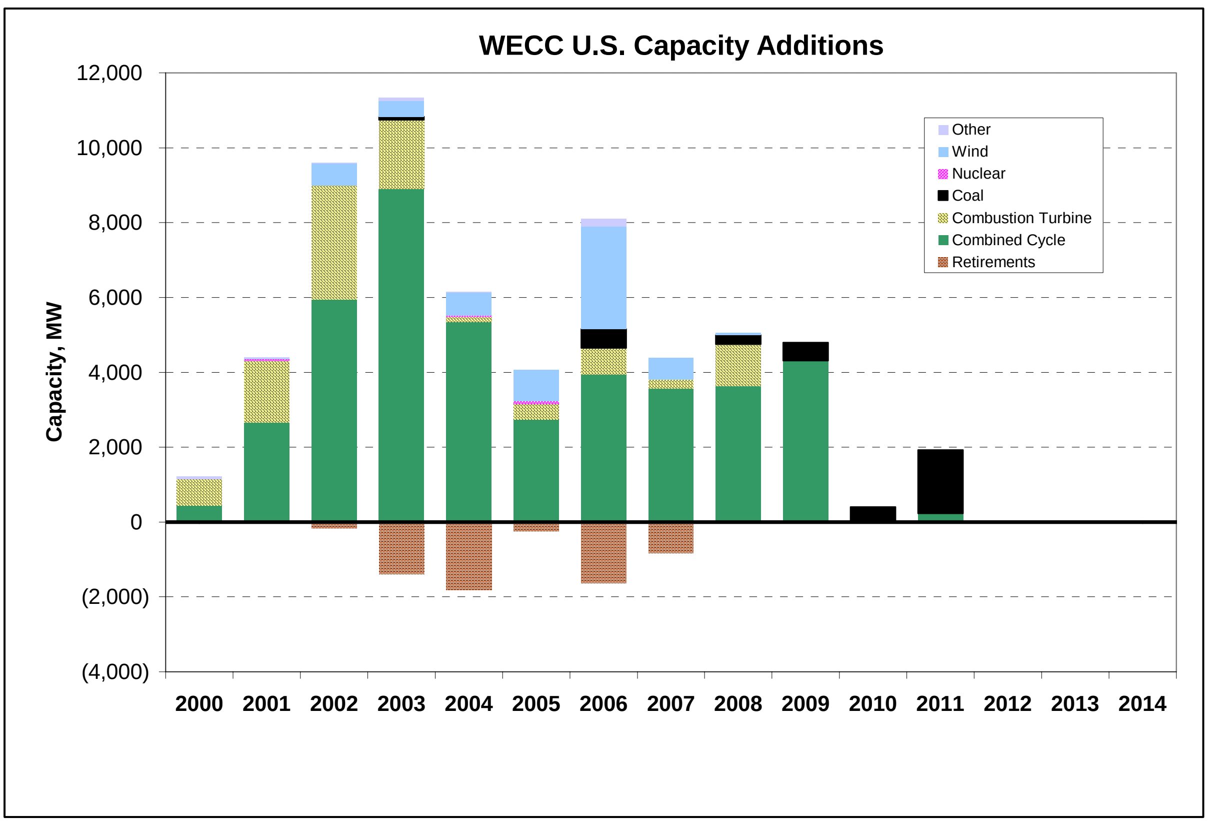

MRO Canada Capacity Additions
Capacity, MW
2,500
2,000
1,500
1,000
500
0
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014

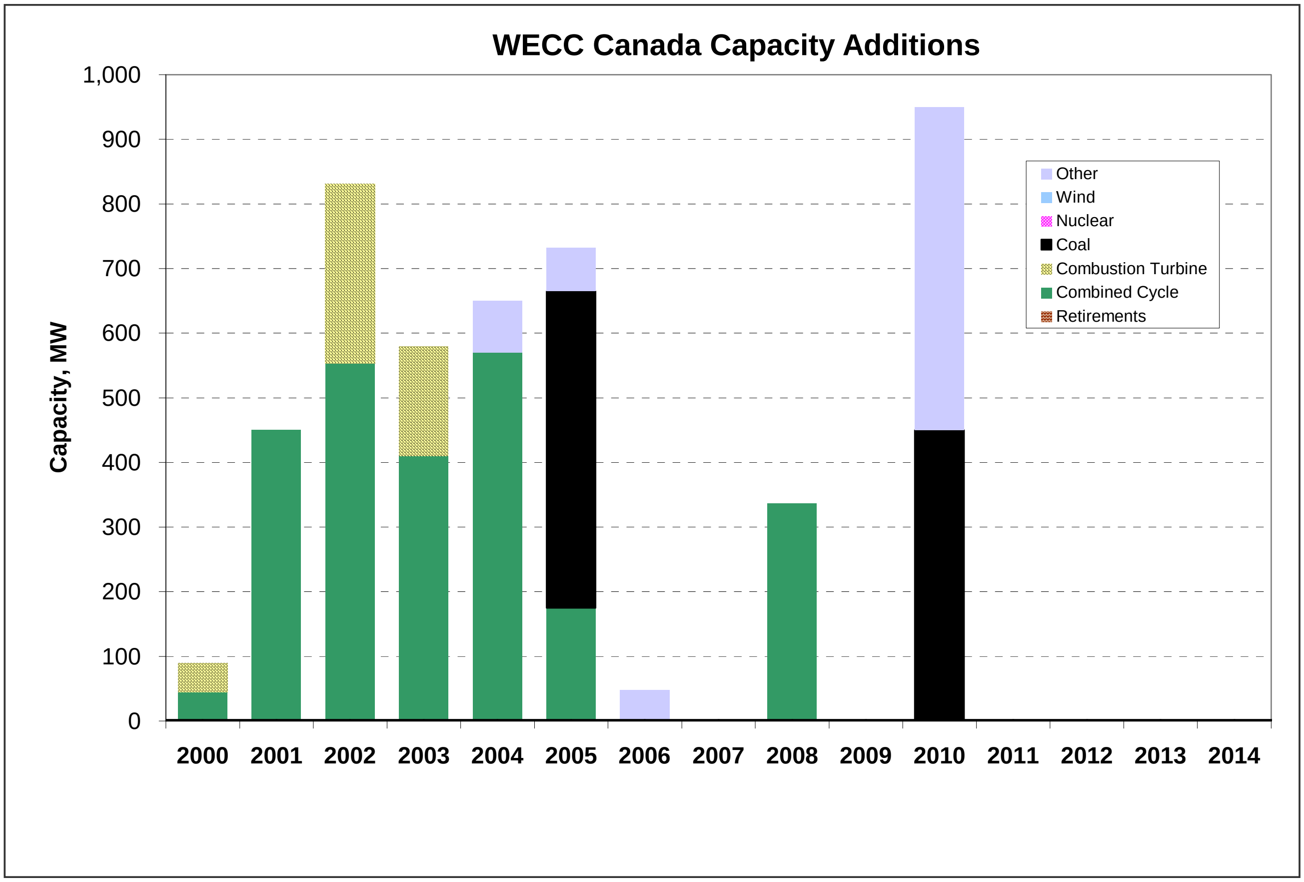

NPCC U.S. Capacity Additions
Capacity, MW
5,000
4,000
3,000
2,000
1,000
0
(1,000)
(2,000)
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014


NPCC Canada Capacity Additions
2,500
1,500
500
(500)
(1,500)
(2,500)
(3,500)
(4,500)
Capacity, MW
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements


SERC Capacity Additions
20,000
15,000
10,000
5,000
0
(5,000)
Capacity, MW
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements


SPP Capacity Additions
Capacity, MW
5,000
4,000
3,000
2,000
1,000
0
(1,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements


WECC U.S. Capacity Additions
Capacity, MW
12,000
10,000
8,000
6,000
4,000
2,000
0
(2,000)
(4,000)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements


WECC Canada Capacity Additions
Capacity, MW
1,000
900
800
700
600
500
400
300
200
100
0
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Other
Wind
Nuclear
Coal
Combustion Turbine
Combined Cycle
Retirements

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Manager of System Planning
Florida Reliability Coordinating Council

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North American Electric Reliability Council