Northeast Power Coordinating Council Interregional Long Range Adequacy Overview

Approved by the RCC

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Conducted by the

NPCC CP-8 Working Group

NPCC CP-8 WORKING GROUP

Philip Fedora (Chair)	Northeast Power Coordinating Council
Alan Adamson	New York State Reliability Council
Scott Brown	New Brunswick System Operator
Gregory Drake	New York Independent System Operator
Greg Hine	Independent Electricity System Operator
Wendell Ingalls	Nova Scotia Power Inc.
Kevan Jefferies	Ontario Power Generation Inc.
J. W. (Jack) Martin	National Grid USA
Pierre Poirier	Hydro-Québec Distribution
Hugo Sansoucy	Hydro-Québec Production
Fei Zeng	ISO New England Inc.

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INTRODUCTION

This study evaluated, on a consistent basis, the long range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Region's plans to meet their Loss of Load Expectation (LOLE) planning criteria [1] through a multi-area probabilistic assessment.

The development of this Overview was in response to Goal #2 of "NPCC's 2006 Organizational Goals" that states:

> "Evaluate on a consistent basis the long range adequacy of NPCC and neighboring regional plans proposed to meet LOLE planning criteria through multi-area probabilistic assessments. Monitor and include the potential effects of proposed market mechanisms in NPCC and neighboring regions to provide for future adequacy in the overview"

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [2] was selected for the analysis. GE Energy was retained by the Working Group to conduct the simulations.

The previous database developed by the NPCC CP-8 Working Group's "*NPCC Summer 2006 Multi-Area Probabilistic Reliability Assessment*", April 2006, [3] was used as the starting point for this Overview. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the 2007-2011 time period.

This report is organized in the following manner: after a brief Introduction, general modeling assumptions are presented, followed by a summary provided by each Area describing their specific representation. The results and observations of the Overview are then presented.

The Overview's Objective and Scope of Work is shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

[1] See: http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/a-02.pdf
[2] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm
[3] See: https://www.npcc.org/publicFiles/documents/seasonalNew/NPCC_Reliability_Assessment_Summer_2006%20Final%20Report.pdf

MODEL ASSUMPTIONS

The assumptions used in NPCC's Long Range Adequacy Overview are consistent with the assumptions of the following recently completed, or currently being finalized Area studies:

Area Studies

New York

On August 22, 2006, the New York Independent System Operator (NYISO) issued its Comprehensive Reliability Plan (CRP), [4] a study that recommends solutions to meet New York's future electric power needs and maintain the integrity of the state's bulk power grid. The CRP identified generation and transmission needs in New York over a 10-year span (2006-2015). The CRP is part of the NYISO's Comprehensive Reliability Planning Process (CRPP), which consists of two studies: a Reliability Needs Assessment [5] (RNA), which identifies potential problems, and the CRP, which recommends specific solutions and outlines whether there is a need for regulated solutions. According to the annual RNA, published in December 2005, the state's transmission and generation resources should be adequate through 2007. However, the RNA identified significant transfer capability reductions through southeastern New York starting in 2008 due to increased power demand and the scheduled retirement of several generating units. Those shortfalls could reach 2,250 megawatts (MW) by 2015 if no action is taken. In the CRP, market-driven solutions and updated project plans by Transmission Owners are expected to maintain reliability of the state's electric grid through 2010. Resource additions planned by private developers – or those already under development – for the New York area are necessary to meet system reliability needs for this time period.

New England

The New England Regional System Plan (RSP) is ISO-New England's annual planning report that identifies the resources and transmission facilities needed to maintain reliable and economic operation of New England's bulk electric power system over a ten-year horizon. A public meeting to discuss ISO-New England's Draft 2006 Regional System Plan (RSP) was held September 7, 2006. The New England 2006 RSP [6] was approved by ISO-New England's Board on October 26, 2006.

Ontario

Ontario is approaching a major milestone in the development of its electricity system. The Ontario Power Authority [7] (OPA) is completing Ontario's first Integrated Power System Plan (IPSP) since the opening of the electricity market in 2002. Looking ahead 20 years, the Plan will identify the conservation, generation and transmission investments

[4] See: http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2004_planning_trans_report/crp_final08222006.pdf

[5] See: http://www.nyiso.com/public/webdocs/newsroom/press_releases/2005/rna_final12212005.pdf

[6] See: http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf

[7] See: http://www.powerauthority.on.ca/

that are needed to ensure a reliable, sustainable power supply and to permit the replacement of all coal-fired generation with cleaner sources of supply. The plan, currently under development, is expected to be released in March 2007 for subsequent approval by the Ontario Energy Board. The IESO is working closely with the OPA to ensure the IPSP meets the operability and reliability requirements of the Ontario grid.

Québec

The Québec area assumptions used in this study are consistent with its most recent NPCC Triennial Review of Resource Adequacy [8] and the follow-up of the Procurement Plan to the Québec Energy Board. [9]

PJM-RTO

The PJM Interconnection Board approved its first 15-year Regional Electric Transmission Expansion Plan [10] (RTEP) on June 23, 2006 to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. To establish a starting point for development of an RTEP, PJM performs a “baseline” analysis of system adequacy and security. These baseline analyses and the expansion plans serve as the base system for conducting feasibility studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies for those projects which decide to go forward.

Load Representation

The loads for each area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies.

Load Shape

The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load. This selection was based on the review of the weather characteristics and corresponding loads of the years from 1988 through 2002.

The growth rate in each month’s peak was used to escalate area loads to match the Area's year 2006 demand and energy forecasts for both load shapes. The impacts of Demand-Side Management programs were included in each area's load forecast for both load shapes.

Load Forecast Uncertainty

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices

[8] See: http://www.npcc.org/adequacy.cfm
[9] See: http://www.regie-energie.qc.ca/en/index.html
[10] See: http://www.pjm.com/contributions/news-releases/2006/20060623-rtep-june-2006.pdf

at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub area load can vary on a monthly basis, Table 1 shows the values assumed for August, corresponding to the assumed occurrence of the NPCC system peak load (assuming the 2002 load shape). Table 1 also shows the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are shaded in Table 1.

Table 1
Per Unit Variation in Load Assumed (Month of January 2007)

Area	Per-Unit Variation in Load						
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.1100	1.0469	0.9952	0.9533	0.9444	0.9000	0.8500
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0444	1.0296	1.0148	1.0000	0.9852	0.9704	0.9556
QC	1.0700	1.0550	1.0400	1.0000	0.9600	0.9450	0.9300
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Generation

Generator Unit Availability

Details regarding the NPCC area's assumptions for generator unit availability are described in the latest NPCC Seasonal Multi-Area Probabilistic Assessment. [11]

Capacity and Load Summary

Figures 1 -6 summarize area capacity and load assumed in this Overview at the time of area peak for the 2007-2011 period. Area peak load is shown against the initial area

[11] See: http://www.npcc.org/adequacy.cfm

capacity, adjusted for purchases, retirements, and additions. More details can be found in Appendix B.

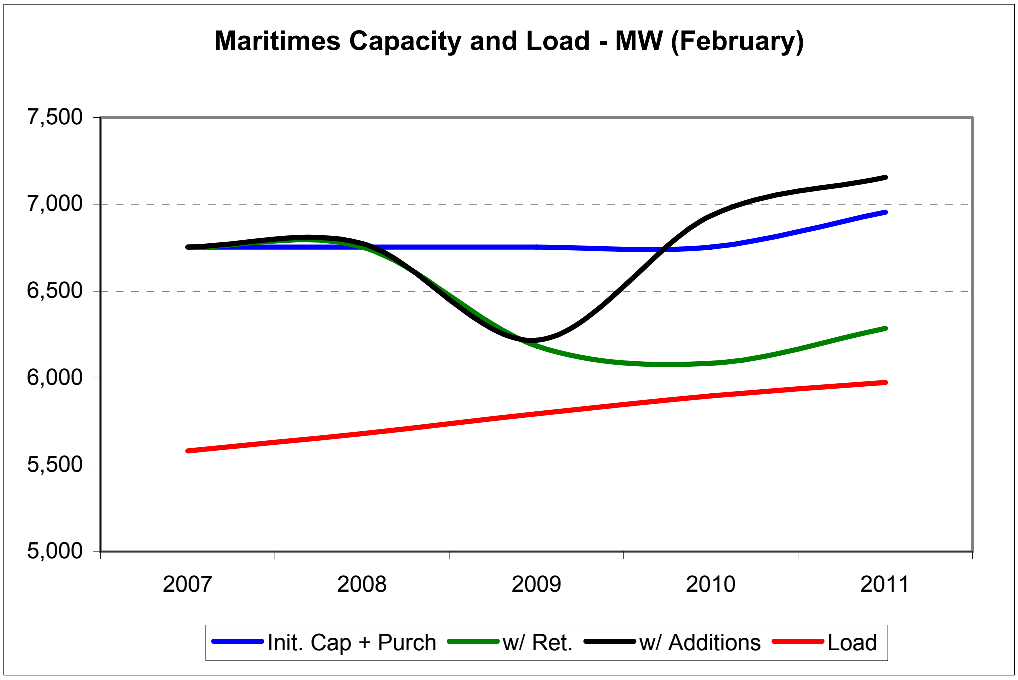

Figure 1 – Maritimes Area Capacity and Load

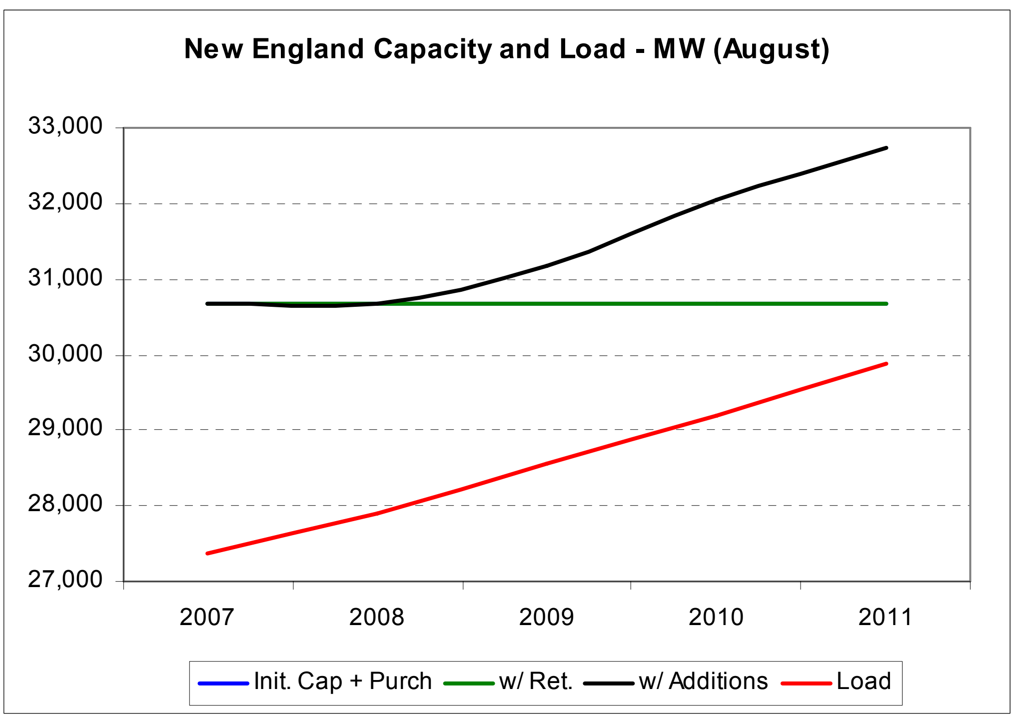

Figure 2 – New England Capacity and Load

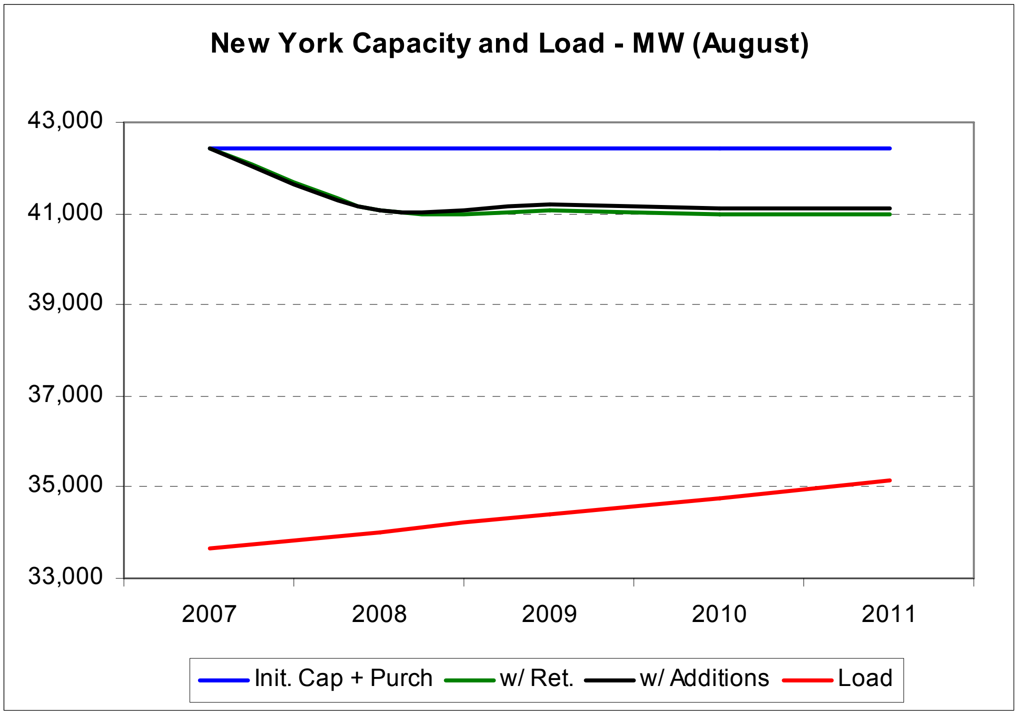

Figure 3 – New York Area Capacity and Load

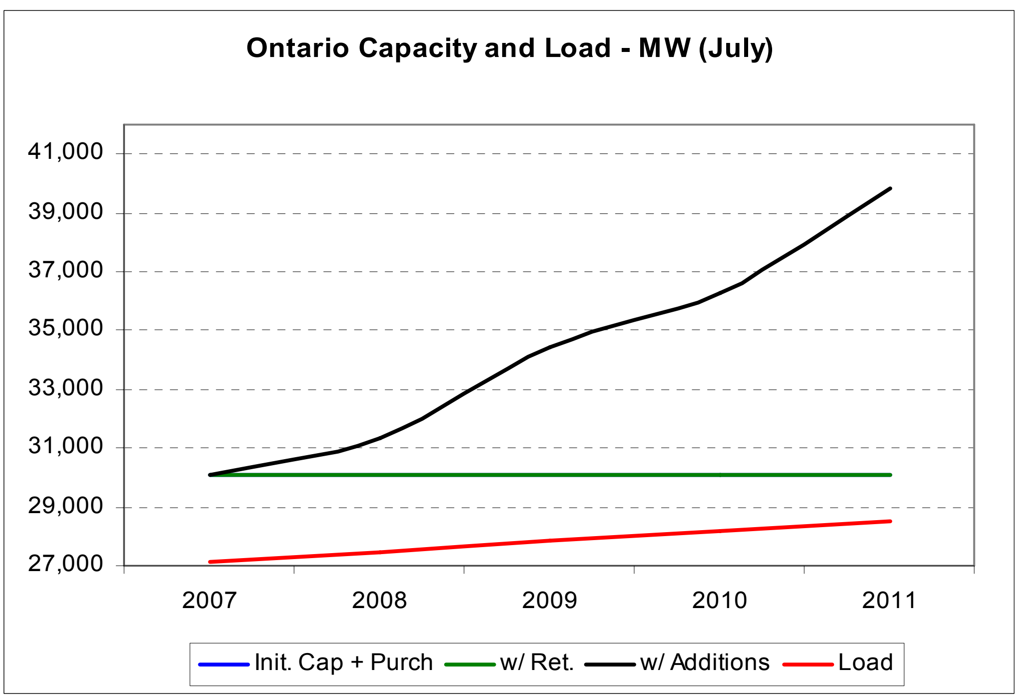

Figure 4 – Ontario Capacity and Load

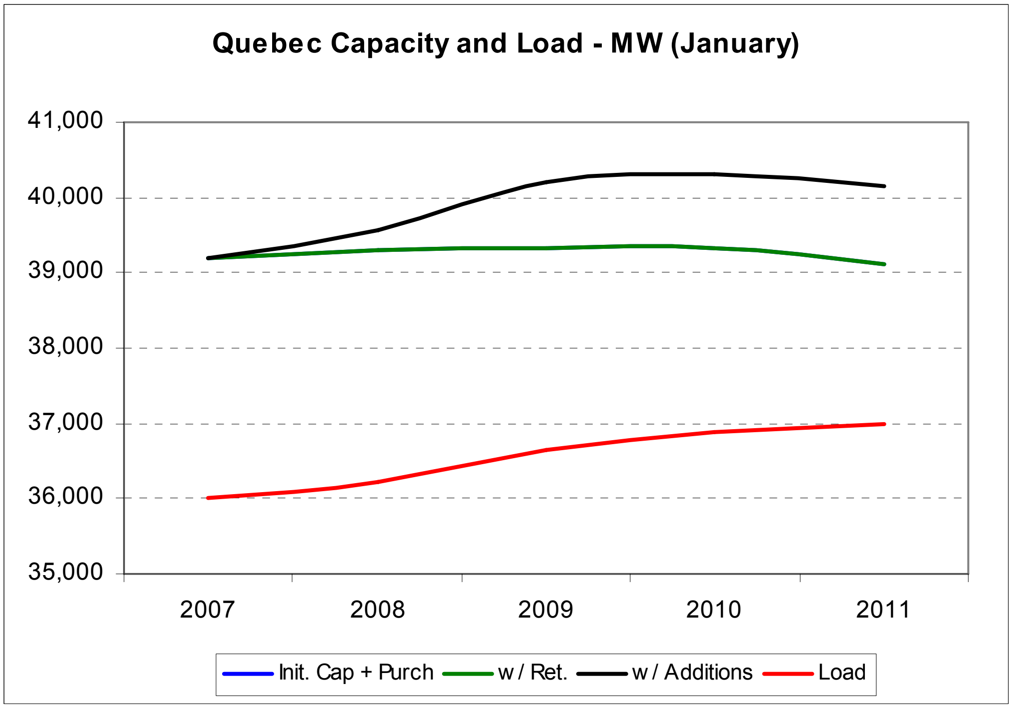

Figure 5 – Québec Capacity and Load

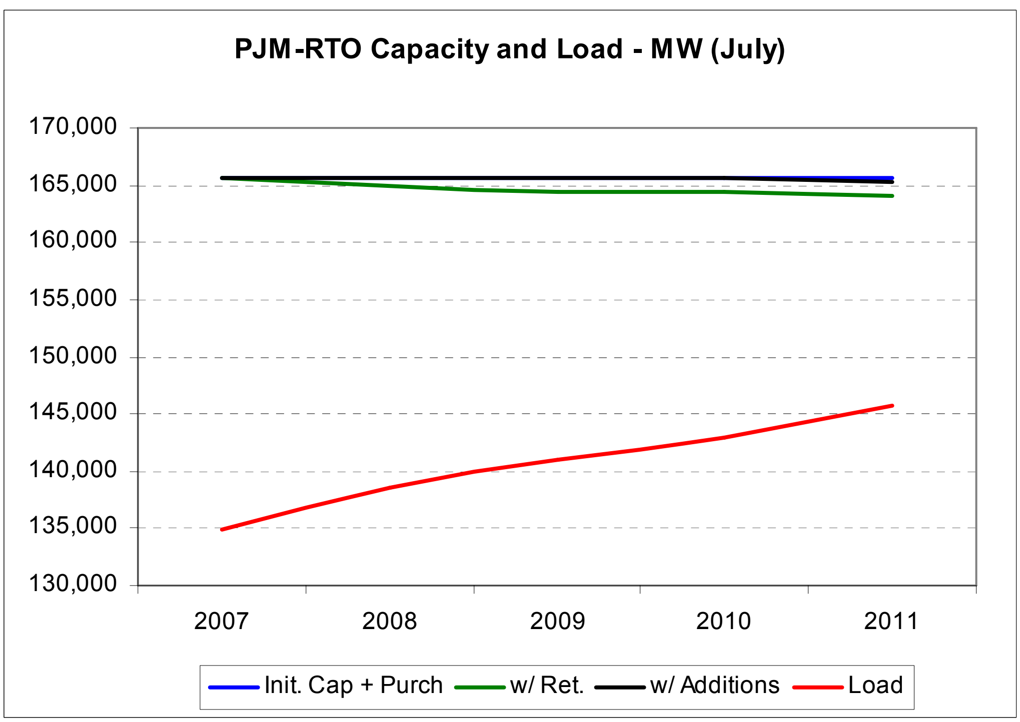

Figure 6 – PJM-RTO Capacity and Load

Transfer Limits

Figure 7 depicts the system that was represented in this Assessment, showing area and assumed transfer limits for the 2007-2011 time period.

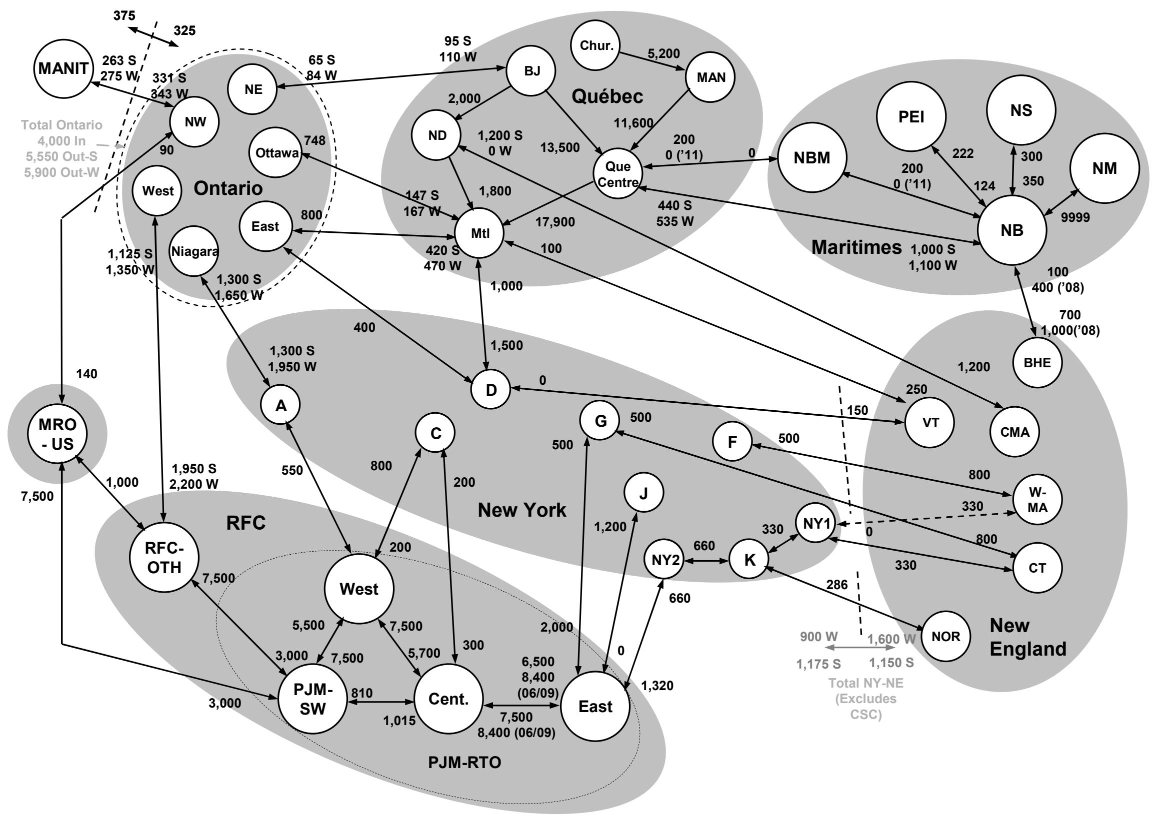

Figure 7 - Assumed Transfer Limits

Transfer limits between and within some areas are indicated in Figure 7 with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 7 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- Reliability*First* Corp.
MRO	- Midwest Reliability Organization	Que Centre	- Québec Centre	MT	- Maritimes Area

Operating Procedures to Mitigate Resource Shortages

Each area takes defined steps as their reserve levels approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

The need for an area to begin these operating procedures is modeled in MARS by evaluating the daily probabilistic expectation at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

Table 2 summarizes the load relief assumptions modeled for each NPCC area. The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 2 was a reasonable approximation for this analysis.

Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month Load Relief Assumptions - MW

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (Aug)	QC (Jan)
1. Curtail Load / Utility Surplus Appeals LRP/SCR/EDRP Manual Voltage Reduction	- - - -	- - 284 [12] -	- - 1,145 0.54% of load	188 1% of load - -	1,023 - - -
2. No 30-min Reserves	233	578	600	473	500
3. Voltage Reduction or Interruptible Loads [13] ELRP [14]	531 -	1.50 % of load	1.43% of load	2.60 % of load 112	200 -
4. No 10-min Reserves General Public Appeals	625 -	1,001 -	- 158	895 -	750 -
5. EDRP General Public Appeals No 10-min Reserves	- - -	- - -	- - 1,200	115 - -	- - -

[12] Derated value shown accounts for assumed availability.
[13] Interruptible Loads for the Maritimes area (implemented only for the Area), Voltage Reduction for all others.
[14] Emergency Load Reduction Program.

Assistance Priority

Table 3 indicates the priority order followed when allocating reserves and assistance to areas with a resource deficiency. Areas listed with equal priority received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all areas and sub-areas.

Table 3
Priority Order for Providing Emergency Assistance

	Priority of Assistance	
Area Providing Assistance	**1ST**	**2ND**
Québec	MT ON	NE NY
Maritimes	QC ON	NE NY
New England	NY	QC MT ON
New York	NE	QC MT ON
Ontario	QC MT	NE NY
Millbank Units	QC	MT
PJM	NE NY	
RFC-OTH	PJM	
MRO	RFC-OTH	

AREA ASSUMPTIONS

Maritimes

The Maritimes area 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.

Load Forecast

Separate demand and energy forecasts are prepared by each of the Maritimes area jurisdictions, as there is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. For area studies, the individual forecasts are combined using the load shape of each jurisdiction. Historically, the ratio of the coincident peak demand of the Maritimes to the sum of the non-coincident peak demands of each of the Maritimes area jurisdictions is 97%.

The Maritimes area peak demand forecast for 2007 is 5,572 MW, which is 70 MW less than the forecast made last year. The projected annual growth rate of the peak demand is 1.5%, which is lower than the 1.7% growth rate forecast last year.

The Maritimes area annual energy consumption forecast for 2007 is 30,520 GWh, which is 356 GWh less than the forecast made last year. The projected annual growth rate of the annual energy consumption is 1.4%, which is lower than the 1.6% growth rate forecast last year.

For area studies of resource adequacy, the Maritimes area uses a Load Forecast Uncertainty (LFU) of 4.6%, which represents the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

Expected Resources

On July 29, 2005, the Province of New Brunswick announced that it would proceed with the planned refurbishment of the Point Lepreau nuclear station, with Atomic Energy of Canada Limited (AECL) as the general contractor. This 18-month refurbishment is to begin in April 2008, and results in a 558 MW capacity reduction for the system during the refurbishment period, and causes the Maritimes area to be deficient by 229 MW in 2008/09. NB Power Distribution and Customer Service is in the process of identifying its capacity needs for the refurbishment period, and is looking at ways to resolve this deficiency.

The current installed wind capacity in the Maritimes area is 55 MW, and projections for total installed wind capacity are 165 MW by 2007, and 400 MW by 2009. By 2016, government targets for installed wind capacity could result in about 1,000 MW of wind capacity for the Maritimes area.

Expected generation retirements include 98 MW (oil) in 2009/10, and 57 MW (coal) in 2010/11.

Expected generation additions include 77 MW (incremental nuclear) from the Point Lepreau refurbishment in 2009/10, 50 MW (incremental gas) in 2009/10, and 200 MW in 2010/11 due to the expiration of a capacity sales contract to Hydro-Québec.

Transmission Projects
Construction of a second 345 kV intertie between New Brunswick and New England is underway, with a scheduled in-service target of December 2007. This new line will connect Point Lepreau, New Brunswick to Orrington, Maine. As a result of this project (including series and shunt capacitors in Maine), the maximum transfer capability between New Brunswick and New England is increased from 700 MW to 1000 MW, and the import capacity from New England to New Brunswick is expected to be raised from 100 MW to 400 MW. This second intertie also significantly improves the reliability of the Maritimes system since loss of either of the two interties to New England will no longer result in the separation of the Maritimes from the interconnected New England power system.

Expected Impact of Market Programs
None.

Fuel
Figure 8 depicts the Maritimes area resource capacity mix by fuel type for the year 2004 on an installed capacity basis.

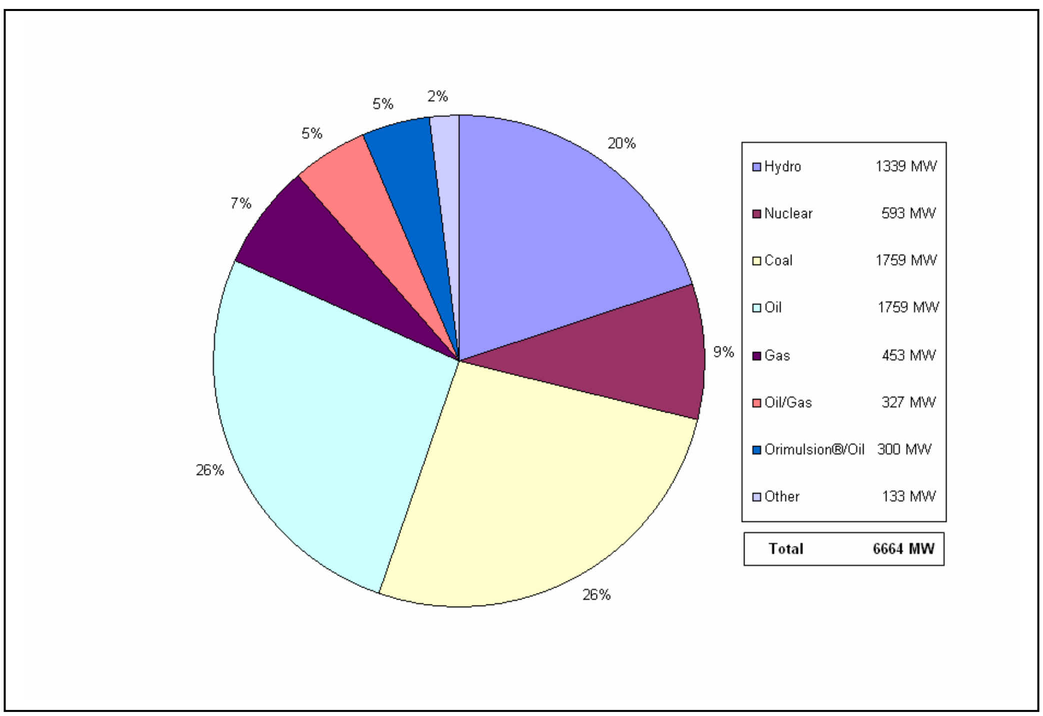

Figure 8 – Maritime Area Capacity Mix by Fuel Type for 2004

New England

Load Forecast

The load forecasts for this assessment are consistent with ISO New England's 10-year (2006 – 2015) forecasts in its 2006 Regional System Plan (RSP06). These forecasts integrate the historical demand for each state, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs on the forecasts. New England's summer-peak demand is projected to grow at a compound annual growth rate (CAGR) of 1.5% from 2006 to 2007 and 1.9%, or 500 MW to 600 MW per year, in the long run. The slower growth rates through 2007 are due in part to the price of electric energy assumptions, which reflects natural gas and fuel oil prices. These prices have sharply risen since 2000 but are expected to decline and then stabilize over the long term. In addition, the region's increased use in air conditioning is decreasing the annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load). This means that the peak hourly load has been increasing relative to average load levels. The sensitivity of system load to weather is represented by the probability distribution of the weekly peak load for each week of the year.

Expected Resources

Consistent with ISO New England's RSP06, all existing resources are modeled, and no capacity retirements are assumed for this assessment. New Boston unit 1, whose reliability agreement will be terminated as of November 15, 2006, is assumed to be deactivated during the assessment period. Figure 9 shows the generation capacity mix by fuel type of the current existing capacity in New England. (Note: "Other Renewables" includes biomass, refuse, landfill gas (LFG), and wind.)

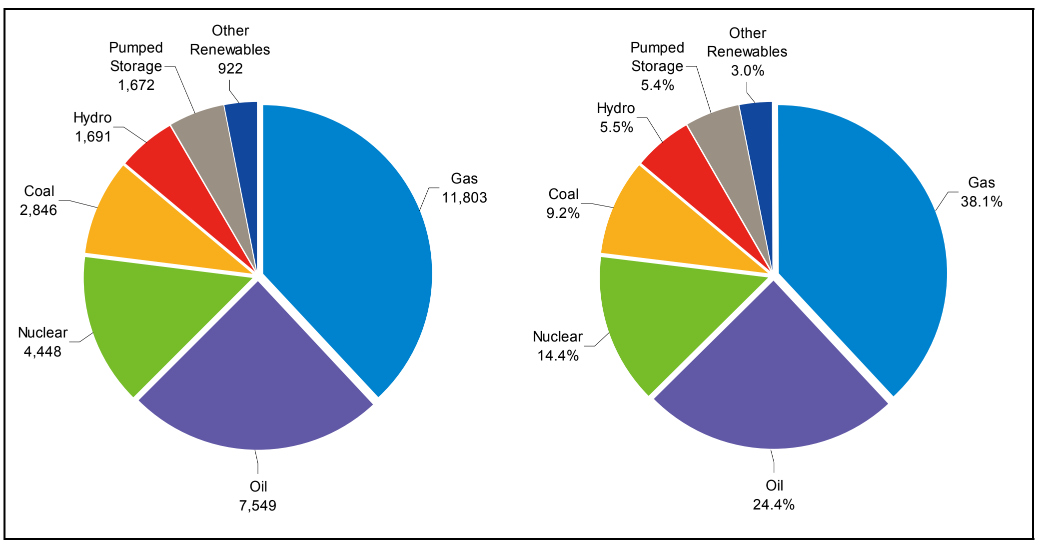

Figure 9 – New England Capacity Mix by Fuel Type for 2006 (Based on Summer Ratings, MW and %)

Table 4 lists the demand-response resources [15] assumed for this assessment. These resources are activated during various OP 4 action steps. These resources are derated in the MARS model to account for their availability performance.

Table 4
New England Demand-Response Programs Assumed

Program	SMD Load Zone	MW Assumed		Performance Rate (%)
		Summer	Winter	
Real-time Two-hour Demand-response	SWCT	0.7	0.7	65.5
	ME	1.0	1.0	100.0
	NEMA/Boston	0.8	0.8	1.2
	WCMA	9.0	9.0	77.6
Real-time Thirty-minute Demand-response	SWCT	256.8	173.3	92.2
	CT	23.9	23.9	89.7
	NEMA/Boston	2.8	2.8	55.0
	SEMA	0.5	0.5	31.0
	VT	0.1	0.1	96.3
	WCMA	0.1	0.1	100.0
Profiled-response	ME	11.0	11.0	77.6
	NEMA/Boston	1.4	1.4	89.4
	VT	5.9	5.9	100.0
	TOTAL	**314.0**	**230.5**	

Expected Transmission Projects
The following major transmission projects are assumed for this assessment:

- **Northeast Reliability Interconnect (NRI) Project**—comprised of a new 144-mile, 345 kV transmission line connecting the Point Lepreau substation in New Brunswick, Canada, to the Orrington substation in northern Maine along with supporting equipment. It is designed to increase transfer capability from New Brunswick to New England by 300 MW. The planned in-service date for this project is the end of 2007.
- **NSTAR 345 kV Transmission Reliability Project**—addresses the reliability needs in the Boston area and increases the Boston-import transfer capability by approximately 1,000 MW. This project includes the construction of a 345 kV substation in Stoughton and the installation of three new underground 345 kV lines: one 17-mile cable to K Street Substation and one 11-mile cable to Hyde Park Substation by 2006; and a second 17-mile cable to K Street Substation in 2007.

[15] For more information on these programs, see http://www.iso-ne.com/genrtion_resrcs/dr/broch_tools/index.html

- **Southwest Connecticut Reliability Project**—addresses the reliability needs in the Greater Southwest Connecticut, including the need to address operating constraints and impediments to interconnecting new generation. Phase 1 includes a 20-mile 345 kV circuit from Bethel to Norwalk, planned to be in service in 2006. Phase 2 includes a 70-mile 345 kV circuit from Middletown to Norwalk, planned to be in service in 2009. The transfer capabilities of SWCT and Norwalk/Stamford interfaces are expected to increase to 2,350 MW and 1,300 MW after Phase 1, and to 3,650 MW and 1,650 MW after Phase 2.

Expected Impact of Market Programs

On June 16, 2006, FERC approved a Settlement Agreement [16] creating a newly designed Forward Capacity Market (FCM) that will replace the current monthly Installed Capacity (ICAP) auctions. The FCM will establish competitive auctions for capacity resources to be held three years ahead of their anticipated need. The Forward Capacity Auction (FCA), which will be held annually, will be a descending clock auction. There are also annual reconfiguration auctions two years, one year, and just prior to the Commitment Period. All qualified capacity resources (existing, new, or imports) may offer/bid into the auction. Capacity clearing in an FCA will be entitled to receive capacity payment based upon performance. The first auction is expected to be held in the first quarter of 2008 for a commitment period beginning June 1, 2010. During the transition period from December 1, 2006 to May 30, 2010, the current UCAP products will be retained, and all listed ICAP resources will receive a monthly capacity payment based on a fixed payment rate that is adjusted annually.

Under the FCM, 100 percent of Installed Capacity Requirement (ICR) needed to meet the once in 10 years resource adequacy criterion will be procured for the power year beginning three years later. In New England's RSP06, ICR for future years were projected under different scenarios. For the years that showed a capacity shortfall, the amount of resources that must be added to the system is determined. Since the type of resources that will be added to the system is presently unknown, generic generator-expansion units were added to the system as needed as resource proxies. These units served to keep the LOLE equal to or lower than the system criterion of not disconnecting firm load more than one day in 10 years. The expansion unit was assumed to be rated at 172.5 MW, with a 10% forced outage rate and requires 5 weeks of maintenance per year. Assuming current FERC approved 2,000 MW of tie-line benefits from neighboring control areas, RSP06 identified that New England will need one such expansion unit by 2009, 6 by 2010, and 10 by 2011. To account for the loss of New Boston unit 1, two additional expansion units are assumed to be added to the system in 2009. For the purpose of this assessment, the above numbers of units are assumed to be added to New England during the assessment period.

[16] http://www.iso-ne.com/regulatory/ferc/filings/2006/mar/er03-563-000_030_055_3-7-06_corrected.pdf

New York

Demand

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 2011. The forecast developed by the NYISO is based on historical weather-normalized loads provided by the transmission-owners of New York State. At forecast load levels, a one-degree increase in the combined temperature humidity index, or CTHI, (an index that weights dry bulb by 60% and dew point by 40%, and includes a lag structure) above the design value of 81.31 will result in about 500 MW of additional load.

Energy

Energy consumption is forecast to grow at an average annual rate of 1.1% through 2011.

Expected Resources

Existing resources are identified in "NYISO's 2006 Load and Capacity Data" book. [17] In addition to this generation, there are 925 MW of new generation under construction (including 98 MW of wind resources). NYISO is also relying on firm purchases totaling 990 MW over the Cross Sound Controllable Line and Neptune Project HVDC cables. Retirements totaling 1674 MW are expected over the period from 2005 through 2011.

NYISO forecasts the continuation of Special Case Resources (SCRs) of approximately 1,080 MW. SCRs are loads capable of being interrupted, and distributed generators rated at 100 kW or higher, that are not directly telemetered. SCRs are installed capacity (ICAP) resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual.

Fuel

Figure 10 shows New York's resource capacity mix by fuel type for the year 2006 on an installed capacity basis.

Table 5 shows the projected installed capacity resource mix from 2007 through 2011. The "other" category includes wind power, resource recovery, wood burning, and other fuels. For the next five years, resources fueled by natural gas will meet all of the growth in projected energy consumption. Except for wind energy, no new resources employing other fuels are expected to be added in the planning period.

[17] See: http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2006_goldbook_public.pdf

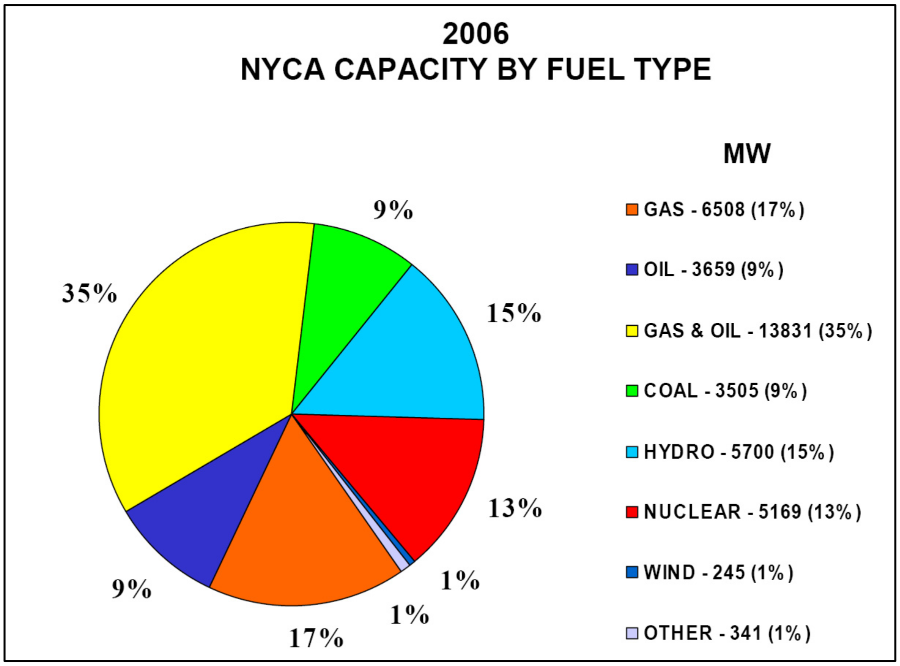

Figure 10– New York Control Area Capacity Mix by Fuel Type for 2006

Table 5
New York Planned Resource Capacity Mix by Fuel Type for July – 2007 to 2011 (%)

Month Of July	Coal	Gas & Oil	Gas Only	Hydro	Nuclear	Oil Only	Wind	Other
2007	8.9	36.2	16.4	14.4	13.1	9.2	0.9	0.9
2008	8.5	36.3	16.5	14.4	13.3	9.3	0.9	0.9
2009	8.1	35.0	17.0	14.9	13.7	9.5	0.9	0.9
2010	8.1	35.0	17.0	14.9	13.7	9.5	0.9	0.9
2011	8.1	35.0	17.0	14.9	13.7	9.5	0.9	0.9

There is a potential for a natural gas shortage in New York State in the winter. This could cause natural gas fired units to burn other fuels or curtail operations. If unit operation curtailment due to fuel unavailability occurs in load pockets, generation from other areas would need to help meet demand, causing heavier loading on the existing transmission system. Many of the dual fired units are the larger older steam units located in load pockets and would impact reliability needs in a multiple ways if retired. The real challenge on a going forward basis will be to maintain the benefits that fuel diversity, in particular dual fired fuel capability, provides today. This will be especially critical in New York City and Long Island which are entirely dependent on oil and gas fired units many of which have interruptible gas transportation contracts. In terms of operational strategy, the New York State Reliability Council has adopted the following local reliability rule:

I-R3. Loss of Generator Gas Supply (New York City & Long Island)

"The NYS Bulk Power System shall be operated so that the loss of a single gas facility (i.e., pipeline or storage facility) does not result in the loss of electric load within the New York City and Long Island zones."

The NYSIO categorizes generation capacity fuel types into three supply risks: Low, Moderate and High.

The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is nearly 7,000 MWs greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10%, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak of 25,500 MW. This would leave a margin of nearly 4,000 MW or 14% of the total capacity characterized by low to moderate fuel risk.

Transmission

Two HVDC ties are available to deliver capacity and energy to New York over the study period. The Cross Sound Controllable Line from New England to New York was completed in 2004 and has recently seen firm capacity contracts established on the order of 330 MW delivered. The Neptune project from Pennsylvania to New York will be able to deliver 660 MW when it is completed in 2007. Another project with transfer capability improvement is the circuit and transformer upgrades from Sprainbrook to Sherman Creek substations. This is modeled as an increase in internal New York transfer capability into New York City by 350 MW in 2007.

Ontario

Demand

The actual summer peak demand for 2006 was 27,005 MW, which is 5.9% higher than the normal weather forecast of 25,502 MW in the latest NERC RAS report.[18] The actual winter peak for 2005/2006 was 23,766 MW, or 2.1% lower than the 24,272 MW normal weather forecast in the previous report.

With the continued growth of cooling load, the summer peak is expected to grow at a faster rate than the winter peak ensuring that Ontario remains summer peaking.

Load Sensitivity Analysis

The IESO uses weather scenarios to capture the variability in demand due to weather. Load Forecast Uncertainty (LFU) - a measure of demand fluctuations due to weather variability - is a critical part of demand analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The IESO resource adequacy assessments use the normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence. An extreme weather scenario is developed based on the most extreme weather experienced over 36 years of weather history. The extreme weather forecast for the summer of 2006 was 27,278 MW. Compared to normal weather, extreme weather results in over 1800 MW of additional demand. This extreme weather scenario is valuable for studying situations where the system is under duress, especially during peak periods.

Energy

The actual Ontario energy demand for 2005 was 157.0 TWh. Due to economic conditions, there has been a significant loss of industrial load. For this reason, annual energy demand is expected to fall short of the 2005 value in both 2006 (154.4 TWh) and 2007 (156.7 TWh).

Resources

Since last summer, more than 800 MW of new supply has been added to the Ontario power system including the 515 MW at the Pickering Nuclear Generating Station and 117 MW of gas-fired co-generation. The total new capacity includes new wind generation from three wind farms installed in Ontario. These facilities have an installed capacity of about 200 MW. The wind projects are listed in Table 6.

Table 6
New Wind Generation in Ontario

Wind Project	Installed Capacity (MW)
Kingsbridge 1 Wind Power Project	39.6
Melancthon Grey Wind Project	67.5
Erie Shores Wind Farm	99

[18] See: ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf

Demand side resources are considered as identified in the list of Emergency Operating Procedures. Emergency Load Reduction Programs (ELRP) at the time of peak is forecast to be 56 MW. Emergency Demand Response Program (EDRP) at the time of peak is forecast to be 115 MW. In addition, there is a forecast of the assumed demand-side management (DSM) values that are coincident with the annual peak demand. These quantities, shown in Table 7, are assumed to reduce demand, prior to initiating any emergency operating procedures.

Table 7
Assumed DSM for Ontario – 2007 to 2011

Year	DSM Value Coincident with Annual Peak (MW)
2007	485
2008	729
2009	976
2010	1,061
2011	1,351

The IESO produces a week by week Outlook of reserve margins, based on levelized risk, which shows a different reserve requirement and different reserve margin for each week of the summer period. The Outlook published in June of 2006 showed an average of 14.3% available reserve during the summer months, compared to an average of 16.0% a year earlier. The weekly requirement in the June Outlook averages about 15.6% for the summer months. However, it should be recognized that the methodology for calculating demand and the methodology for determining the hydroelectric resource availability have been changed. The methodology changes result in lower reserve values this year, despite the fact that the overall resource adequacy situation is better than it was before.

Under median and high demand growth assumptions, resources that are currently available within Ontario, together with the expected new resources and/or available imports, are sufficient to meet the NPCC resource adequacy criterion from 2007-2011.

Considerable steps have been taken and are planned to enable retirement of Ontario's coal-fired units (6,500 MW). In executing these changes, flexibility is essential to accommodate the large amounts of new generation required and the impact of each change on the entire system. Careful and continuous coordination and adjustment of plans is taking place to ensure successful implementation of the coal replacement program while maintaining reliability.

Future generating resource capacity additions of 9,815 MW are under construction or planned to come into service during the study period 2007 to 2011. At the present time, IESO is working with Ontario Power Authority (OPA) to ensure reliability in Ontario while reducing coal-fired emissions. The Ontario government has a policy to shut down the coal plants once replacement capacity is available. The plants will remain in operation as required to maintain reliability. It is assumed that coal fired generation will continue to be available during the study timeframe of 2007 to 2011.

The fuel mix at the time of summer peak for 2007 is shown in Figure 11.

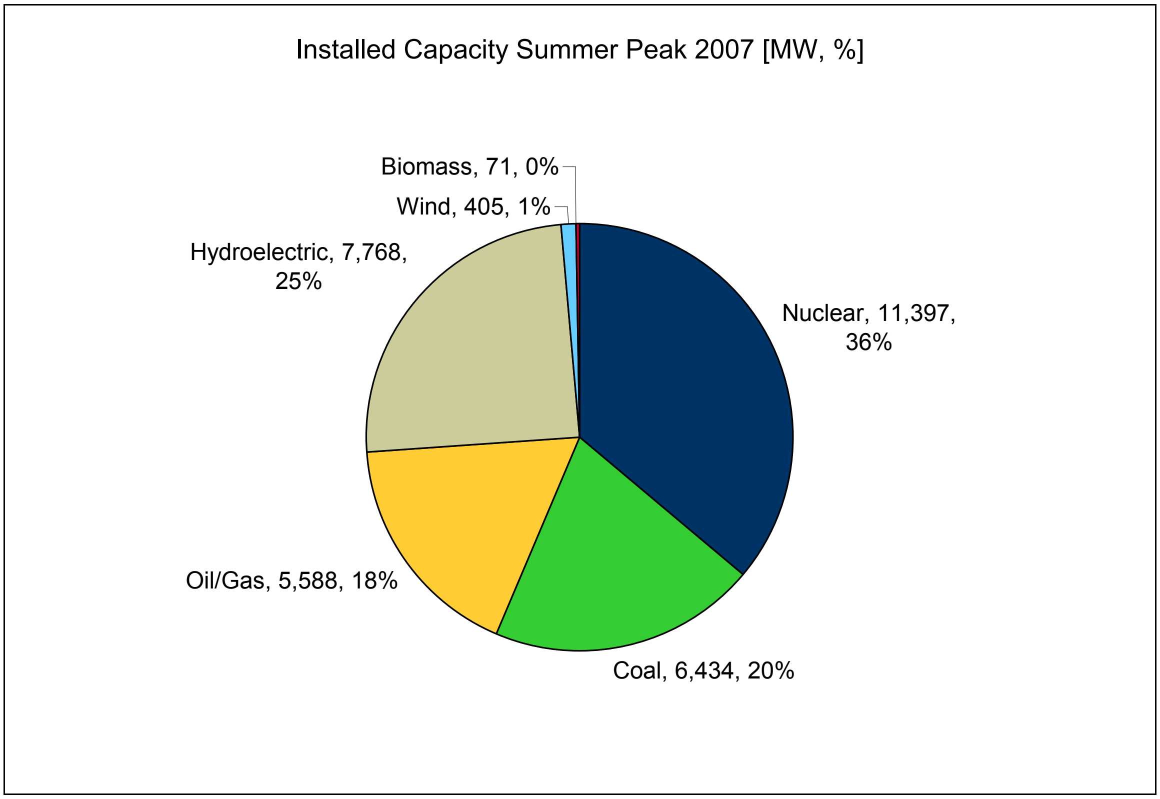

Figure 11 – Ontario Capacity Mix by Fuel Type for Summer 2007

Table 8 shows the projected installed capacity resource mix from 2007 through 2011, at the time of the annual peak.

Table 8
Ontario Planned Capacity Mix by Fuel Type at Time of Annual Peak – 2007 – 2011 (%)

Fuel Type	2007	2008	2009	2010	2011
Coal	20	19	18	17	16
Gas/Oil	18	19	24	25	28
Hydroelectric	25	25	23	22	21
Nuclear	36	35	32	30	32
Wind	1	2	3	4	4
Biomass	0	0	0	1	1

Ontario Power Authority 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 OPA's first integrated power system plan (IPSP) is expected to be developed later in 2006, with Ontario Energy Board approval targeted for 2007. The IPSP will address Ontario electricity needs for the next 20 years. Generation deliverability to load is not currently an issue in Ontario and future requirements will be managed as part of the IPSP.

Fuel

In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the IESO has joined with Union Gas, Enbridge, TransCanada Pipelines and the Ontario Energy Board to form the Ontario Gas Electric Interface Working Group (OGEIWG). This group will establish communication protocols, cross-functional training, contingency analysis and gas-electric day coordination in order to manage operational and reliability issues in both energy sectors. The Ontario Energy Board also has proceedings underway to review infrastructure and tariff issues.

The IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel supply limitations are anticipated. In general, fuel delivery infrastructure redundancy for non-renewable resources such as coal, uranium, oil and gas is sufficient such that more explicit analysis is considered only on an ad hoc basis.

Transmission

Transmission capability into the Greater Toronto Area (GTA) has been enhanced over the past year with the addition of the second 500/230 kV, 750 MVA auto-transformer at the Parkway TS in the fall of 2005, a 240 MVAR shunt capacitor at the Essa TS and the planned removal of deratings on the 500/230 kV, 750 MVA autotransformer at the Trafalgar TS.

Imports from New York were limited at times by transmission constraints internal to Ontario in the summer 2005. These limitations are being addressed by augmenting the five existing 230 kV circuits between Niagara Falls and Hamilton that form the Queenston Flow West interface with a new 230 kV double circuit line between the Allanburg TS and the Middleport TS. This expansion project, together with improved 230 kV circuit ratings in the Burlington area, will remove these internal restrictions. New York imports are still expected to be limited, at times, by the ties to New York, although a net increase in import capability of about 350 MW is expected, once the required improvements have been completed. However, there have been delays in implementing all of the required improvements.

In addition, an existing Special Protection System at St. Lawrence has been reactivated and is available under peak load conditions to maximize simultaneous import capability from Hydro Quebec and New York.

A number of other transmission reinforcements are being developed to permit the connection of new generation to the Ontario system. Most significant of these is the need to increase transmission capability from the area around the Bruce nuclear plant to accommodate the return of the two nuclear units and new supply from up to 1,000 MW of wind. The final arrangements have not been decided, but they will need to be in service by 2012 to avoid constraining the additional generation associated with the restart of two nuclear units and the addition of substantial amounts of wind power.

Operations

The phase angle regulators (PARs) are available for service on the Michigan Ontario interconnections but are currently bypassed. High loop flows continue to be present through the Ontario System. The phase shifters have been installed by Hydro One in Ontario to mitigate the problems caused by the loop flows affecting Ontario's most heavily used interfaces. However, this equipment cannot be used as intended until IESO and the Mid-West System Operator (MISO) complete a corresponding operating agreement, which is currently awaiting negotiations between with Hydro One and the International Transmission Company.

The inability to regulate flows combined with lower than expected ratings on the PAR equipment resulted in significant congestion of imports from the Michigan direction in 2005. Beginning in summer 2006, the IESO, the Midwest ISO, Hydro One and International Transmission Company, have agreed to temporarily bypass the phase angle regulators for normal operation until an agreement is reached to make full use of their regulating capability. This increases Ontario's transfer capability to and from Michigan by 300 to 400 MW in the summer. Due to a forced outage, 230 kV circuit B3N (230 kV Scott – Bunce Creek circuit) has been out of service since 2003. Current work is on-going to restring the circuit and it is currently expected to become available within the study period.

The IESO has been working with government and stakeholders to address some of the problems that surfaced last summer when the IESO relied on extensive use of emergency control actions in order to maintain reliability and avoid power interruptions. These measures, which were implemented in 2006, include:

- A Day Ahead Commitment Process which is expected to reduce the failure of import transactions in real time and increase commitment certainty for both domestic and out of province generators; and,
- An Emergency Load Reduction Program which will reduce consumption when required for reliability by providing incentives to loads to reduce their energy usage under stressed system conditions.

The IESO has achieved significantly better blackstart preparedness after the blackout in August 2003 by procuring additional blackstart capability and requiring actual line energization tests annually in conjunction with existing generator black start tests.

Québec

Load Forecast

Québec's winter-peak demand is projected to grow at a compound annual growth rate (CAGR) of 0.7% from 2007 to 2011. The long term load forecasting is done by modeling economic activity, population distribution and growth, residential, commercial and industrial activity and is based on a 30 year analysis of average weather. The monthly internal peak forecast is done using typical weather conditions for each winter month.

Québec uses different sets of load multipliers. For the first four years of the study, the load multipliers increase annually to reflect a higher uncertainty further in time. After four years, the load multipliers remain constant. These annual load multipliers were used in the last NPCC Québec Triennial Review of Resource Adequacy. [8]

In addition, Hydro-Québec Production has firm export commitments of 455 MW to neighbouring networks outside Québec.

Expected Resources

All existing resources are modeled. New generation includes 986 MW from five hydroelectric projects (Mercier, Eastmain 1, Péribonka, Chute-Allard, Rapides-des-Coeurs). All five projects are currently under construction or in partial commercial operation. In December 2006, wind power installed capacity will total 322 MW and is planned to increase to approximately 2,500 MW by December 2011. Capacity contribution from wind power is not currently considered but is being evaluated.

Some industrial loads can be called upon to reduce their consumption during peaking conditions. The de-rated amount of interruptible loads is approximately 1,000 MW from December to March in all years of this assessment. De-rating reflects operational constraints. A 200 MW capacity purchase contract from New Brunswick expires in November 2011.

Figure 12 shows Québec installed capacity by fuel type (including Churchill Falls).

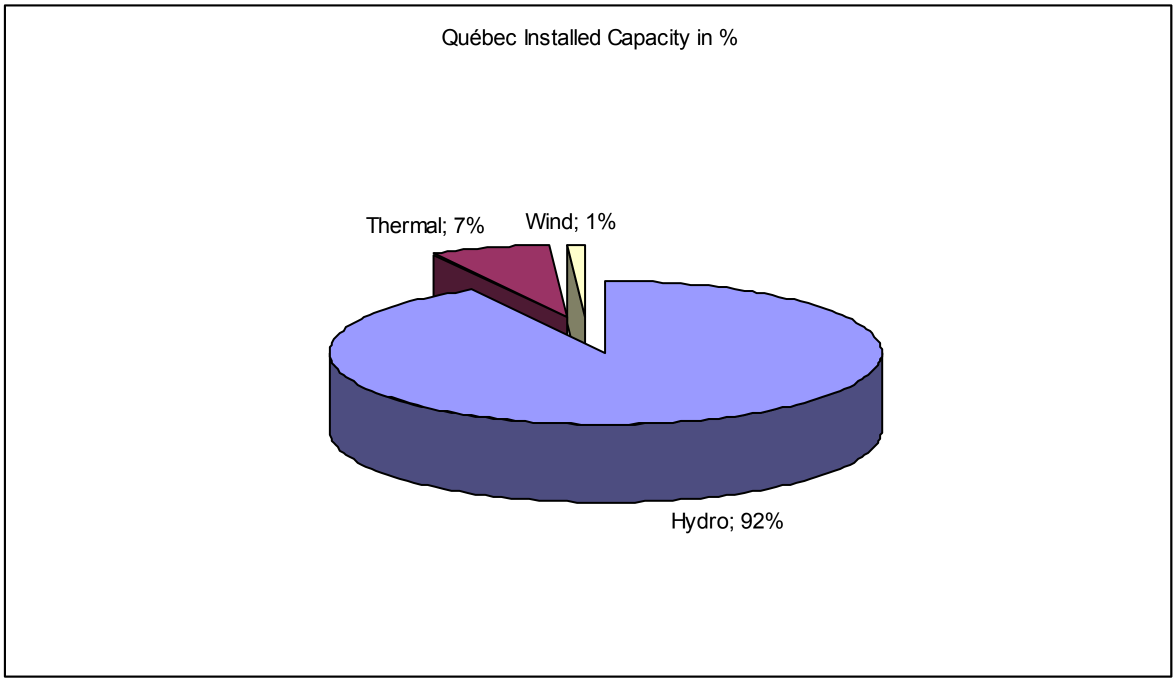

Figure 12– Québec Capacity Mix by Fuel Type

Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of RFC (Reliability*First* Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 9 and Figure 13.

Table 9
RFC and MRO 2006/07 Assumptions [19]

	PJM	RFC-Other	MRO-US
Peak Load (MW)	113,347	88,070	25,265
Peak Month	January	January	January
Assumed Capacity (MW)	175,626	119,894	35,017
Purchase/Sale (MW)	-1,774	0	0
Reserve (%)	53	36	39
Weighted Unit Availability (%)	88.3	83.8	83.1
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	2,061	2,000	270
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	0	1,100
No 10-min Reserves (MW)	634	736	500
Appeals (MW)	400	0	200

[19] Load and capacity assumptions based on NERC's Electricity, Supply and Demand Database (ES&D) available at: http://www.nerc.com/~esd/

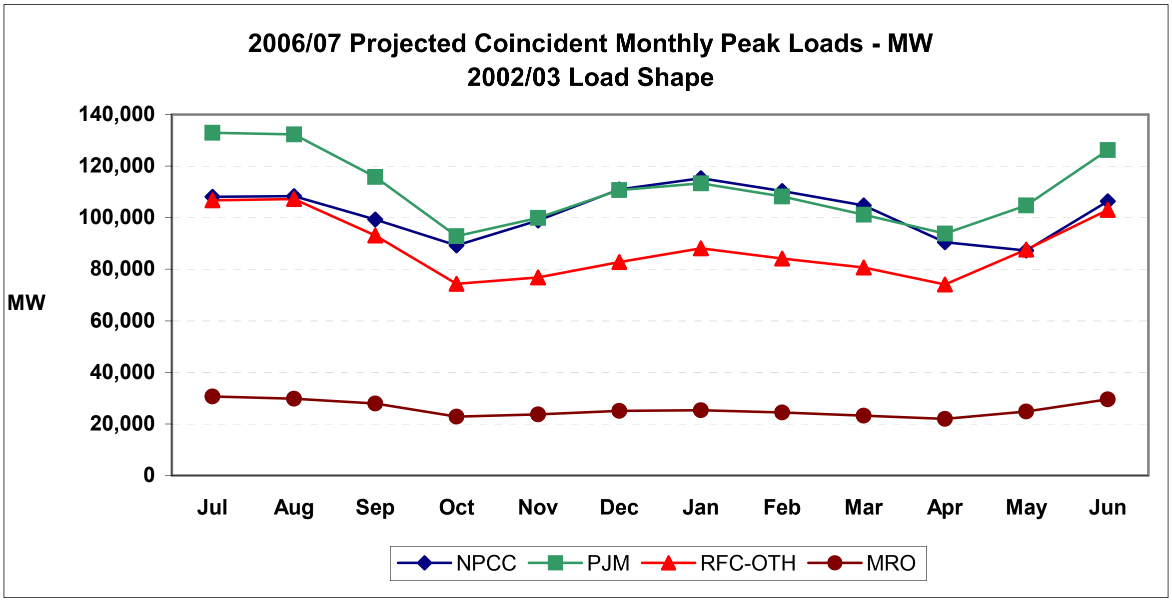

Figure 13 - 2006/07 Projected Monthly Expected Peak Loads for NPCC, RFC, PJM and the MRO

Reliability*First*

Reliability*First* is a newly formed not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.

Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations. The year 2006 is a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities are identified and transferred to Reliability*First*.

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2005 NERC *Electricity Supply & Demand* (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR. The MAIN and ECAR boundaries do not correctly define the new RFC boundaries, but this definition insures consistency within the use of the 2005 NERC ES&D data. The correct load and capacity for the non-PJM MAIN and ECAR region data are drawn out to model the reserves for this area.

Unit data was from the publicly available NERC data. From that data we represented each individual unit in the non-PJM RFC region, assigning each unit performance characteristics based on NERC class averages. The NERC class average characteristics were obtained from the 2005 update of NERC pc-GAR application, using the latest five year period of 2000-2004 for the determination of the class average data.

MRO

The Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability of the bulk power system in the North Central part of North America. The primary focus of the MRO is ensuring compliance with regional and international reliability standards and criteria utilizing open, fair processes in the public interest.

Formation of the MRO was approved by the Mid-Continent Area Power Pool (MAPP) Executive Committee in November 2002. In 2005, this organization became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council.

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. This allowed a straight forward approach to develop the load and capacity data public sources such as the 2005 NERC ES&D data. From that data we represented each individual unit in the MRO-US area, assigning each unit performance characteristics based on NERC class averages. The NERC class average characteristics were obtained from the 2005 update of NERC pc-GAR application, using the latest five year period of 2000-2004 for determining of the class average data.

The MRO-US boundary definition was based on the NERC data which still included the MAIN region. Going forward, the NERC data boundaries will change due to the new RFC region and the corresponding boundary changes between RFC, MRO and SERC. For this model, the previous MRO, MAIN, ECAR and SERC boundaries applied with this expected to evolve for future studies as more current data becomes available.

PJM-RTO

Load Model

The load model used for the PJM-RTO corresponds to the PJM Planning division's technical methods to produce a load model of the forecast years in the study, calendar years 2007 through 2011.[20] The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, February 2006, for the forecast monthly loads. This study modeled load forecast

[20] Please refer to PJM Manuals 19 and 20, as well as the "PJM Generation Adequacy Analysis Technical Methods" at http://www.pjm.com/planning/res-adequacy/downloads/20040621-white-paper-sections12.pdf, for technical specifics.

uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, the period years the model is based on, sampling size, and how many years ahead in the future the load forecast.

Expected Resources

The generation resources correspond to the publicly available EIA-411 data, submitted on or before April 1, 2006. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Active Load Management (ALM) is reflected in this model's Emergency Operating Procedure level 1, corresponding to the publicly available data on the PJM web site (http://www.pjm.com/planning/res-adequacy/downloads/2006-pjm-load-report.pdf). This modeling of Active Load Management corresponds to the PJM Operations Staff ability to call up to 10 ALM events, in a peak period.

Expected Transmission Projects

The transfer values shown in the study are reflective of peak load flow model conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, per the TEAC information available on the PJM web site.[21]

Expected Impact of Market programs

On September 29, 2006, PJM filed a Settlement Agreement [22] on behalf of numerous specified Settling Parties in FERC Docket Nos. ER05-1410 and EL05-148, concerning the Reliability Pricing Model (RPM). The settlement, which is supported or not opposed by the great majority of parties in the proceeding, makes a number of changes to the RPM proposal filed by PJM on August 31, 2005, including changes to the demand curve, use of 3-year forward (instead of 4-year forward) auctions, a Fixed Resource Requirement Alternative, and a peak-period generator availability metric. The Settlement proposes to implement RPM with the annual planning period that starts June 1, 2007. To enable PJM and market participant systems and business practice changes for RPM auctions that will start in April 2007, the Settling Parties asked FERC to approve the settlement, without change, by December 22, 2006.

The technical modeling requirements for the proposed RPM are consistent with the existing modeling and methods used at PJM, per the above modeling summaries used in this study.

[21] See: http://www.pjm.com/committees/teac/teac.html
[22] See: http://www.pjm.com/documents/ferc/documents/2006-d.html

Modeling

The modeling of PJM-RTO breaks the PJM region into four distinct areas: Eastern Mid-Atlantic (PJM Load Forecast Report, February 2006 Table C3), Central Mid-Atlantic (PJM Load Forecast Report, February 2006 Table C1), Western Mid-Atlantic, and the PJM Western areas combined with PJM South. This modeling follows known operational models and constraints while recognizing that areas with high reserves have few events invoking emergency operating procedures. The model in this study used many of the same modeling assumptions used in the PJM 2006 reserve requirement study.[23] This assessment was coordinated with the PJM 2006 reserve requirement study, results of which also available on the PJM web site. [24] [25]

For the PJM-RTO, the Mid-Atlantic Eastern and Central regions comprise almost all of the LOLE shown in the results section of this report with the primary contributor being the Eastern Mid-Atlantic area. Other PJM planning assessments also indicate that the eastern part of the PJM region is at higher risk for invoking emergency operating procedures for future planning periods.

Fuel

Figure 14 shows PJM-RTO's resource capacity mix by fuel type for the year 2006 on an installed capacity basis.

[23] See: http://www.pjm.com/committees/planning/downloads/20051130-item8-pjm-irm-letter.pdf
[24] See: http://www.pjm.com/committees/planning/downloads/20060426-item04-2006-reserve-requirement-study.pdf
[25] See: http://www.pjm.com/committees/planning/downloads/20060426-item04-2006-irm-study-results.pdf

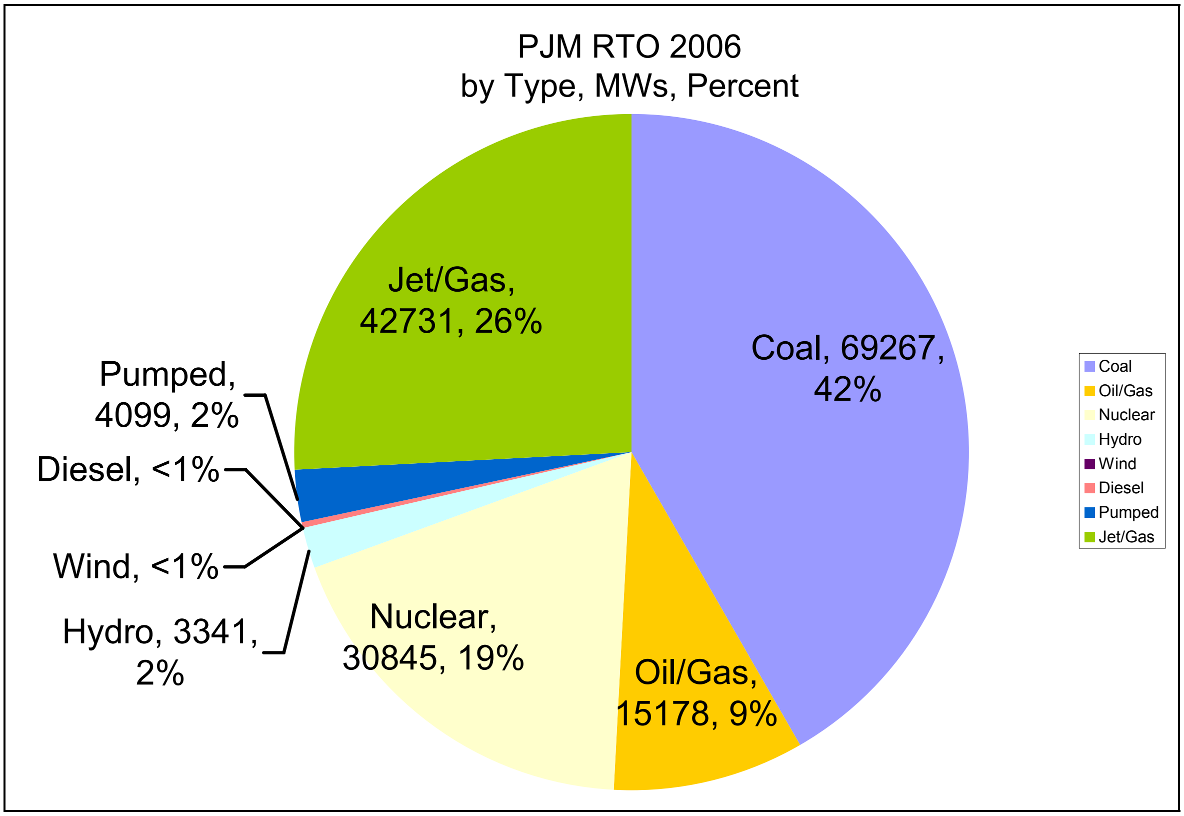

Figure 14 – PJM-RTO Capacity Mix by Fuel Type for 2006

Table 10 shows the projected installed capacity resource mix from 2007 through 2011. The table shows a relative stable resource mix throughout the study period.

Table 10
PJM-RTO Planned Capacity Mix by Fuel Type – 2007 – 2011 (%)

Fuel Type	2007	2008	2009	2010	2011
Coal	41	41	42	42	42
Gas/Oil	8.8	8.5	8.5	8.3	8.2
Hydroelectric	2	2	2	2	2
Nuclear	19	19	19	19	19
Jet/Gas	26	26	26	26	26
Wind	0.07	0.07	0.10	0.10	0.10
Diesel	0.3	0.3	0.3	0.3	0.3
PSH	2.5	2.5	2.5	2.5	2.5

RESULTS

Figures 15 (a) and 15(b) summarize the annual Area Loss of Load Expectation (LOLE) estimated for the 2007-2011 period. For the PJM-RTO, the LOLE levels shown are primarily influenced by the Eastern Mid-Atlantic area.

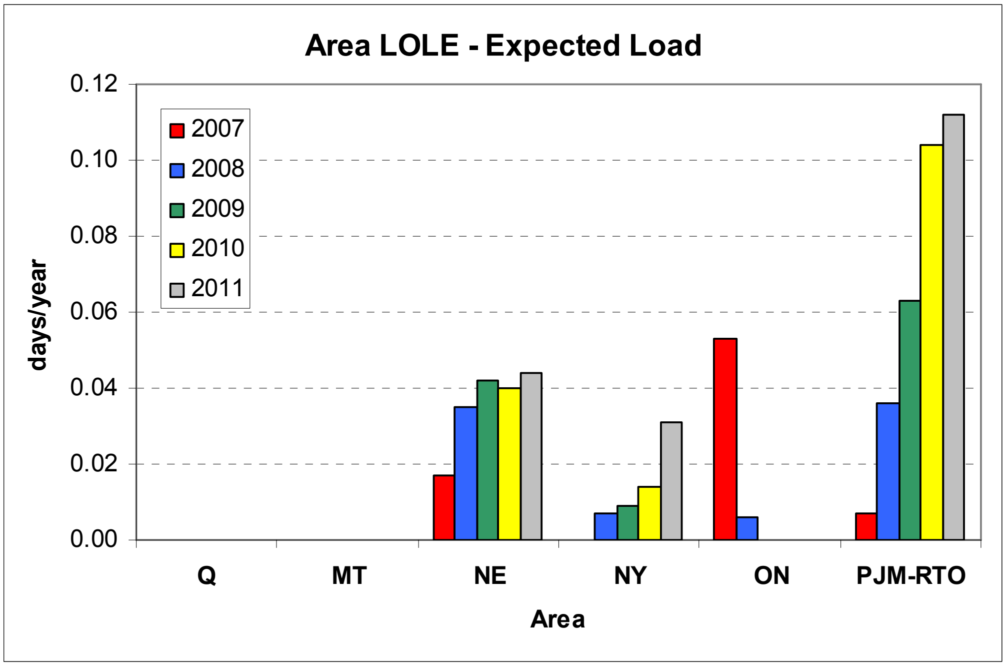

Figure 15(a) - Summary of Annual Area LOLE (2007 – 2011)

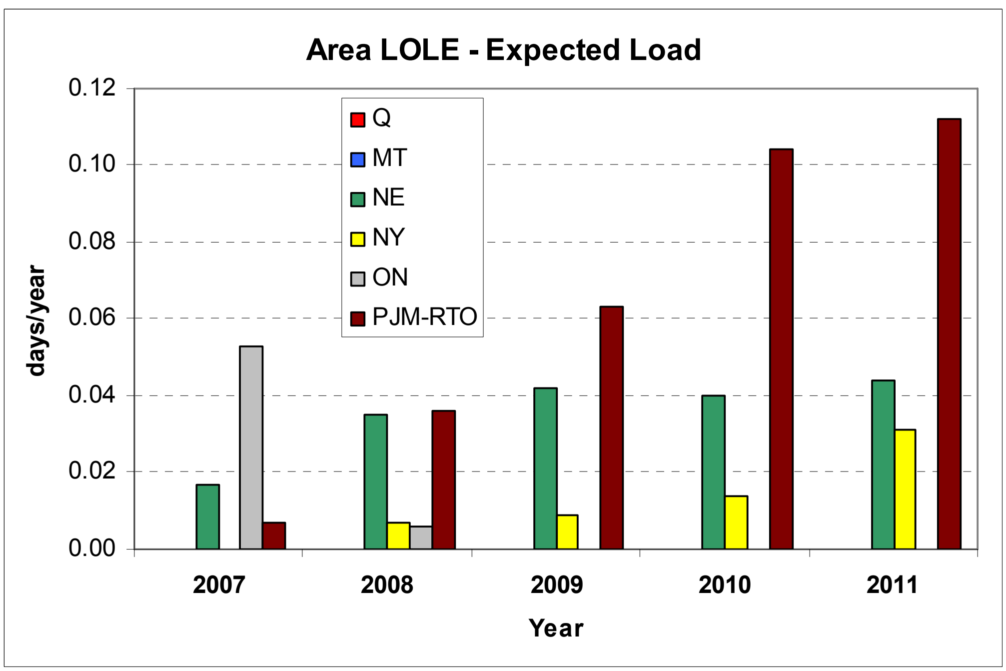

Figure 15(b) - Summary of Annual Area LOLE (2007 – 2011)

OBSERVATIONS

Figures 16(a) and 16(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from the last five NPCC Summer Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

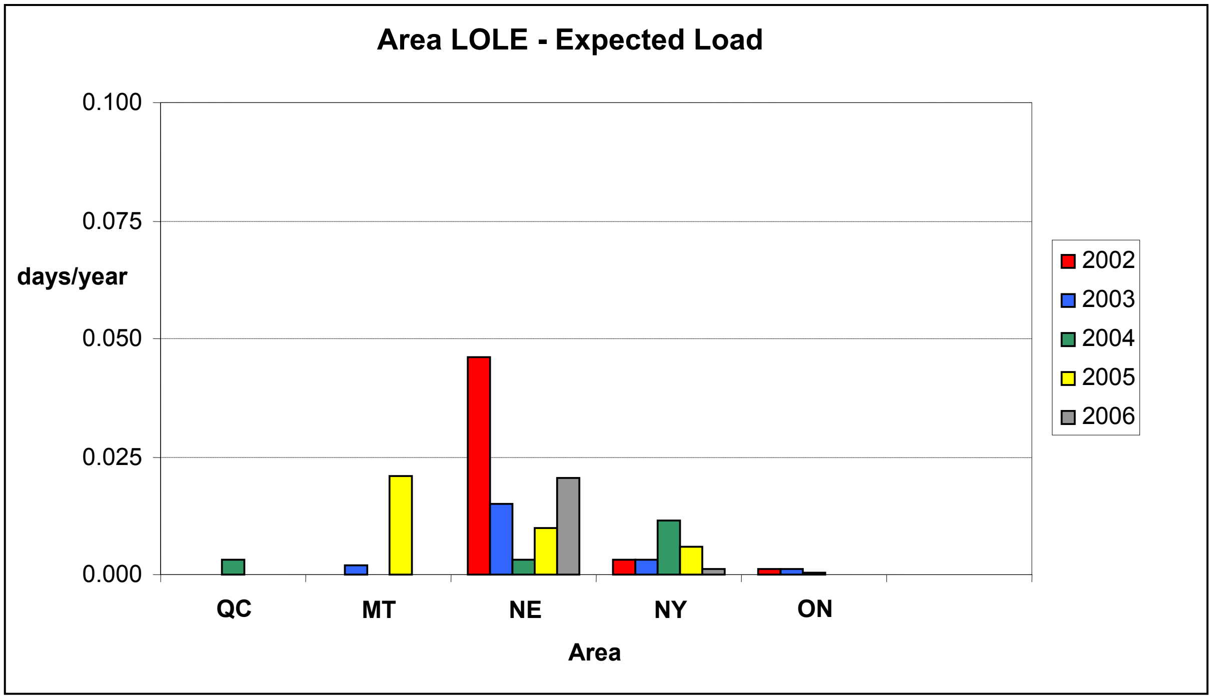

Figure 16(a) - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)

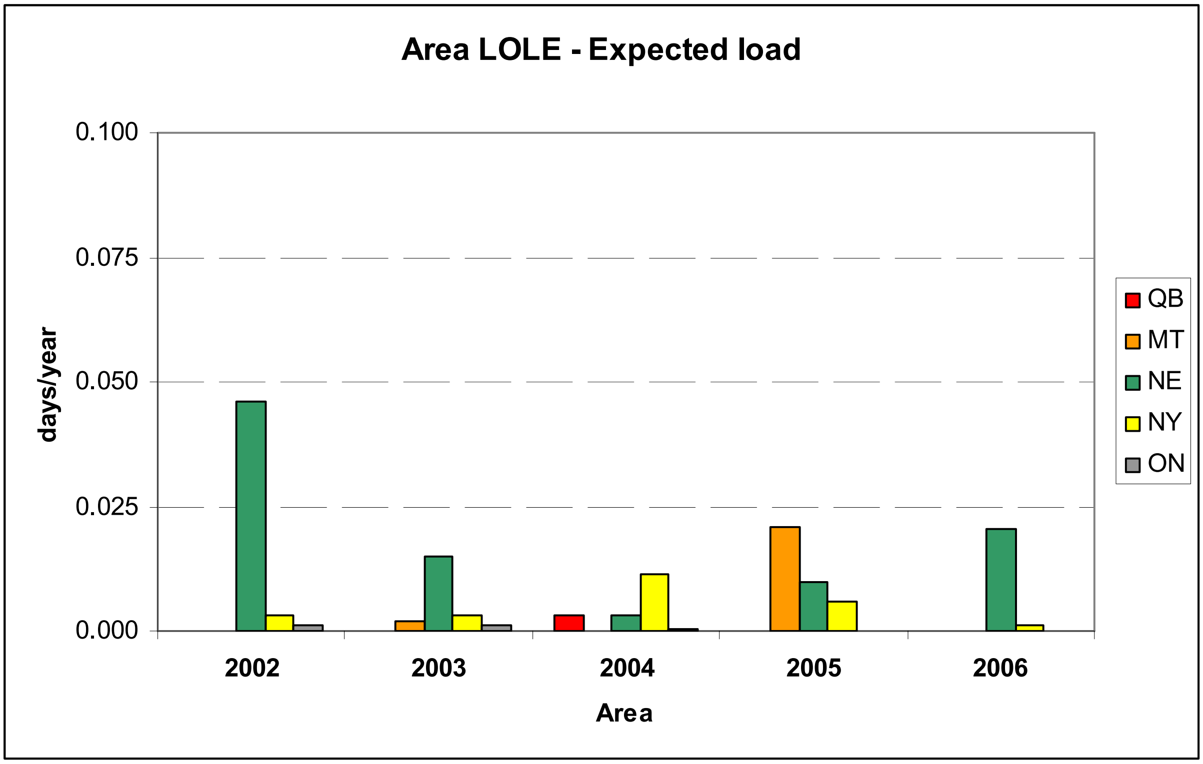

Figure 16(b) - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)

This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 15(a) and 15(b) summarized the annual Area LOLE for the next five years based on the results of the NPCC Interregional Long Range Adequacy Overview. While the LOLE is under 0.1 days/year for NPCC Areas, the results illustrate an upward LOLE trend for New York, New England, and PJM over the time period.

APPENDIX A

Objective and Scope of Work

1. **Objective**
   On a consistent basis, evaluate the long range adequacy of NPCC and neighboring regional plans proposed to meet their respective resource adequacy planning criteria through multi-area probabilistic assessments. Monitor and include the potential effects of proposed market mechanisms in NPCC and neighboring regions to provide for future adequacy in the overview.

2. **Scope**
   In meeting this objective, the CP-8 Working Group will use the G.E. Multi-Area Reliability Simulation (MARS) program to review the resource adequacy of NPCC and neighboring areas for the next five years (2007 – 2011), recognizing uncertainty in forecasted demand, likely completion of proposed transmission and generation projects, anticipated retirements, forced and scheduled outages of generation facilities, and demand response programs. Resource adequacy will be measured by calculating the Loss of Load Expectation (LOLE). A report summarizing the results of the overview will be published no later than December 1, 2006. The overview will:

   - Use the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2007 - 2011 time period;
   - Include the impacts of Sub-Area transmission constraints;
   - Incorporate, to the extent possible, a detailed GE MARS reliability representation for regions bordering NPCC; and,
   - Incorporate, as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

APPENDIX B

Capacity and Load at Time of Peak

Base Case with 2002 Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2007								
	Jan	Feb	Aug	Aug	Jul	Jul	Aug	Jul
Capacity (MW) *	32,821	6,954	30,538	39,552	30,099	167,561	115,824	37,118
Purchase/Sale (MW)	6,372	-200	126	2,885	0	-1,891	0	0
Load (MW)	35,997	5,581	27,381	33,654	27,102	134,967	109,618	31,288
Reserves (%)	9	21	12	26	11	23	6	19
Maintenance - Peak Week (MW)	**	147	58	143	767	96	0	0
Max. Wind Capacity (MW) *	0	11	0	302	405	169	13	290
2008								
	Jan	Feb	Aug	Aug	Jul	Jul	Aug	Jul
Capacity (MW) *	33,083	6,974	30,538	38,186	31,360	167,549	116,746	37,118
Purchase/Sale (MW)	6,489	-200	126	2,885	0	-1,891	0	0
Load (MW)	36,222	5,680	27,906	34,018	27,447	138,638	111,017	31,939
Reserves (%)	9	19	10	21	14	19	5	16
Maintenance - Peak Week (MW)	**	147	58	112	728	96	0	0
Max. Wind Capacity (MW) *	0	23	0	302	571	225	13	290
2009								
	Jan	Feb	Aug	Aug	Jul	Jul	Aug	Jul
Capacity (MW) *	33,691	6,418	31,055	38,311	34,414	167,595	117,250	37,668
Purchase/Sale (MW)	6,507	-200	126	2,885	0	-1,891	0	0
Load (MW)	36,637	5,794	28,561	34,387	27,859	141,039	112,856	32,492
Reserves (%)	10	7	9	20	24	17	4	16
Maintenance - Peak Week (MW)	**	147	58	112	716	96	0	0
Max. Wind Capacity (MW) *	0	36	0	302	1,261	225	13	290
2010								
	Jan	Feb	Aug	Aug	Jul	Jul	Aug	Jul
Capacity (MW) *	33,795	7,135	31,918	38,214	36,306	167,595	118,236	37,668
Purchase/Sale (MW)	6,507	-200	126	2,885	0	-1,891	0	0
Load (MW)	36,873	5,898	29,191	34,761	28,156	142,992	114,747	33,079
Reserves (%)	9	18	10	18	29	16	3	14
Maintenance - Peak Week (MW)	**	147	58	112	758	96	0	0
Max. Wind Capacity (MW) *	0	58	0	302	1,461	225	13	290
2011								
	Jan	Feb	Aug	Aug	Jul	Jul	Aug	Jul
Capacity (MW) *	33,856	7,156	32,608	38,214	39,820	167,212	118,236	37,668
Purchase/Sale (MW)	6,307	0	126	2,885	0	-1,891	0	0
Load (MW)	36,997	5,975	29,891	35,140	28,521	145,713	116,657	33,742
Reserves (%)	9	20	10	17	40	13	1	12
Maintenance - Peak Week (MW)	**	147	58	96	792	96	0	0
Max. Wind Capacity (MW) *	0	79	0	302	1,461	225	13	290

*** Wind capacity included at maximum output for the month**

**** Capacity for Quebec reflects scheduled maintenance and restrictions**