Northeast Power Coordinating Council

2012 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
Frank Ciani	New York Independent System Operator
Kevan Jefferies	Ontario Power Generation Inc.
Scott Leuthauser	Hydro-Québec Energy Services (US) Inc.
J. W. (Jack) Martin	National Grid USA
Kamala Rangaswamy	Nova Scotia Power Inc.
Abdelhakim Sennoun	Hydro-Québec Distribution
Rob Vance	New Brunswick System Operator
Vithy Vithyananthan	Independent Electricity System Operator
Fei Zeng	ISO New England Inc.

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NPCC 2012 LONG RANGE ADEQUACY OVERVIEW

INTRODUCTION

This study evaluated, on a consistent basis, the long range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Regions' plans to meet their Loss of Load Expectation (LOLE) planning criteria [1] through a multi-area probabilistic assessment for the period from 2013 to 2017, and fulfills NPCC's requirements of the NERC Probabilistic Assessment.

At the December 2008 NERC Planning Committee (PC) meeting, the PC approved the formation of a Generation & Transmission Reliability Planning Models Task Force (G&TRPMTF) with two main deliverables in the scope:

- ✓ to evaluate approaches and models for composite generation and transmission (G&T) reliability assessment; and,
- ✓ provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC's long term reliability assessments.

At the September 2010 PC meeting, the G&TRPMTF Final Report on Methodology and Metrics was approved. [2] The metrics recommended in the Final Report included the : (i) annual Loss-of Load Hours (LOLH), (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.

The *2012 Pilot Probabilistic Assessment* [3] conducted with the recommended metrics was approved by the NERC PC at their June 2012 meeting; the assessment recommended:

- ✓ the format of assessment results for future years; and,
- ✓ that the assessment be conducted on a biennial basis.

The *2013 Probabilistic Assessment* is to be completed by the spring of 2013, using the NERC *2012 Long Term Reliability Assessment* reference case data. The assessment will study the years of 2014 and 2016 and include complete coverage of all NERC assessment areas.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [4] was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. MARS version 3.14 was used for the assessment.

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[1] See: https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf , Directory No. 1, Section 5.2

[2] See: http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF%20Meth%20&%20Metrics%20Report%20final%20w.%20PC%20approvals,%20revisions.pdf

[3] See: http://www.nerc.com/files/2012_ProbA.pdf

The database developed by the NPCC CP-8 Working Group's "*NPCC Reliability Assessment for Summer 2012*", April 2012, [5] 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 2013-2017 time period, consistent with the information reported for the *NERC 2012 Long-Term Reliability Assessment*. [6]

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 are shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

[4] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm
[5] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx , Appendix VIII
[6] See: http://www.nerc.com/page.php?cid=4|61

MODEL ASSUMPTIONS

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

Area Studies

New York

This study was based upon the 2012 Reliability Needs Assessment [7] (RNA), published on September 18, 2012 in accordance with its Comprehensive System Planning Process (CSPP). The NYISO's CSPP encompasses the existing reliability planning processes with the new economic planning process called the Congestion Analysis and Resource Integration Study (CARIS). The 2012 RNA provides a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system conducted over a ten-year Study Period (2013-2022). The RNA evaluates the New York Bulk Power Transmission Facilities to determine if Reliability Criteria are met, and identifies Reliability Needs if they are not met.

The 2012 RNA identified two types of reliability issues: transmission security violations, which could manifest as soon as 2013, and resource adequacy violations, which could occur by 2020.

The NYISO's previous RNA (completed in 2010) found that the state's electric power resources (generation, transmission and demand-side program) would meet reliability needs through 2020, assuming energy efficiency programs and planned resource additions proceed as anticipated and no significant facilities were retired from service. There are several reasons cited by the 2012 RNA for reliability needs related to resource adequacy by 2020. The main reason is that generation modeled in the 2012 RNA is about 1,000 megawatts less due to retirements or mothballing of generating units. In addition, the load forecast for 2020 is slightly higher, and the amount of projected demand-side resources is slightly lower.

Based on the finding of reliability needs in the 2012 RNA, the next steps in the NYISO's comprehensive planning process are requests for market-based and regulated solutions. Following an analysis and evaluation of the solutions received, the NYISO will develop and issue a Comprehensive Reliability Plan (CRP) that will determine how the reliability needs identified in the RNA are resolved by the solutions.

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[7] See: http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2012_RNA_Final_Report_9-18-12_PDF.pdf

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 2012 RSP and other planning issues facing the New England region was held on September 13, 2012. The New England 2012 RSP [8] was approved by ISO-New England's Board of Directors on November 2, 2012.

The economic recession has slowed the growth of the summer peak demand, while wholesale electricity markets and other factors have stimulated the development of supply and demand resources and transmission infrastructure to meet the needs of the New England region. Operational challenges, such as LNG supply issues to NEMA/Boston, are being addressed, and the issues for further analysis are being incorporated into the planning process. To meet future system needs, the planning process considers the likelihood of power plant retirements, the expected development and integration of the region's renewable resources, the impact of public policies, and the close interaction between the natural gas and electric power system infrastructure.

The region's heavy dependence on natural-gas-fired generation to meet its electricity needs is expected to grow, with the likely retirement of old coal and oil units and their replacement, in whole or in part, with generators in the queue, and with the possibility of nuclear outages or retirements. At the same time, environmental and economic incentives provided by governmental policies are encouraging the development of low-emitting, renewable resources, such as wind and solar. Passive demand resources are expected to increase as well, as shown by the ISO's energy-efficiency forecast for this planning period. Economic studies are showing the effects of these types of resources and possible new imports from Canada, providing useful information for policymakers and resource developers. Also, smart grid technologies are being developed to improve the electric power system's performance and operating flexibility and its potential to grow active demand resources.

RSP12 and its associated *RSP Project List*, needs assessments, and solutions studies provide detailed information about the system changes needed to reliably serve load in New England for the next 10 years. Transmission projects are in various stages of development, and many have begun or have completed the siting process. Elective and merchant transmission facilities, in various stages of development, have the potential to provide access to renewable resources in remote areas of the region and in neighboring areas.

[8] See: http://www.iso-ne.com/trans/rsp/index.html

In its Strategic Planning Initiative, the ISO has identified risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and possible mitigating actions. Through an open process, regional stakeholders and the ISO are developing an approach to address these issues, which could include further infrastructure development as well as changes to the wholesale electricity market design and the system planning process. Through current and planned activities, the region is well positioned to meet all challenges to reliable and economic system performance.

Ontario

The Independent Electricity System Operator of Ontario regularly assesses the adequacy and reliability of Ontario's power system. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update [9] provides Ontario's supply outlook over the next 18 months. New resources - two refurbished units at the Bruce nuclear station plus the province's first grid-connected solar farm - as well as new tools to effectively integrate renewable resources are described.

Approximately 2,200 megawatts (MW) of grid-connected renewable capacity will be added to the system between December 2012 and May 2014, including the completion of Ontario's first transmission-connected solar project, a 100 MW solar farm in Haldimand County. By May 2014, distribution- and transmission-connected wind and solar generation in Ontario is expected to reach approximately 5,500 MW.

The refurbishment and reliable operation of two Bruce nuclear units is an integral requirement for the scheduled elimination of coal-fired capacity. Both Bruce nuclear units have now completed commissioning; once these units have demonstrated sustained reliable performance, Ontario will be in a good position to continue the removal of coal-fired generation from the system.

Québec

The Québec assumptions used in this study are consistent with its 2012 NPCC Interim Review of Resource Adequacy [10] and the 2012 NERC Long-Term Reliability Assessment. [11] Major resource assumptions include:

- ✓ The retirement of the La Citière oil G.S. (280 MW) & the Tracy thermal G.S. (450 MW);
- ✓ The delayed commissioning of one unit of La Sarcelle hydro G.S (50 MW);
- ✓ The retirement of the Gentilly-2 nuclear G.S which was previously expected to be refurbished from 2013 to 2014 (a decrease of 700 MW from the expected capacity after refurbishment); and,
- ✓ The mothballing period extension of the natural gas unit operated by TransCanada Energy (TCE) beyond the period covered by this review (547 MW).

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[9] See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2012nov.pdf

[10] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[11] See: http://www.nerc.com/page.php?cid=4|61

Maritimes

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area. The assumptions used in this study are consistent with its most recent NPCC Maritimes Review of Resource Adequacy; [12] results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

On October 19, 2011 the New Brunswick government released its new energy blueprint, a three year energy strategy aimed at reducing and stabilizing energy prices, providing energy security, ensuring reliability of the electrical system, environmental responsibility, and providing effective regulation. The plan amalgamates the NB Power group of companies and the New Brunswick System Operator into a single vertically integrated Crown utility but will not affect resource adequacy in the Maritimes Area.

The 660 MW Point Lepreau Nuclear Generating Station was placed back into service at the end of November 2012. Even without Point Lepreau capacity, the Maritimes Area meets the NPCC resource adequacy criterion for all years from 2013-15.

PJM-RTO

The annual PJM Reserve Requirement Study (RRS) [13] calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and Reliability*First* Corporation (RFC) in compliance with Standard BAL-502-RFC-02. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load with sufficient reserves.

The results of the RRS provide key inputs to the PJM Reliability Pricing Model (RPM). The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process, pursuant to Schedule 6 of the PJM Operating Agreement, for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

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.

[12] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[13] See: http://pjm.com/~/media/planning/res-adeq/2012-pjm-reserve-requirement-study.ashx

Load Shape

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the 2003 – 2004 load shape has been used for the winter assessments. The selection of these load shapes was confirmed earlier this year based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008.

For a study such as this that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2002, 2003, and 2004. January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2003 and 2004 were adjusted by the ratios of their annual energy to the annual energy for 2002. This adjustment removed the load growth that had occurred from 2002, from the 2003 and 2004 loads, so as to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match the monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

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 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 and annual basis, Table 1 shows the values assumed for January 2013, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite 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, the reliability indices were calculated for the expected load conditions, derived from computing the reliability at each of the seven load levels modeled, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Table 1
Per Unit Variation in Load Assumed (Month of January 2013)

Area	Per-Unit Variation in Load						
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.0934	1.0383	0.9971	0.9635	0.9402	0.8500	0.8000
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0835	1.0557	1.0278	1.0000	0.9722	0.9443	0.9165
QC	1.0837	1.0825	1.0368	0.9999	0.9632	0.9255	0.9163
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. [14]

Capacity and Load Summary

Figures 1 through 6 summarize area capacity and load assumed in this Overview at the time of area peak for the 2013-2017 period. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance. More details can be found in Appendix B.

[14] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

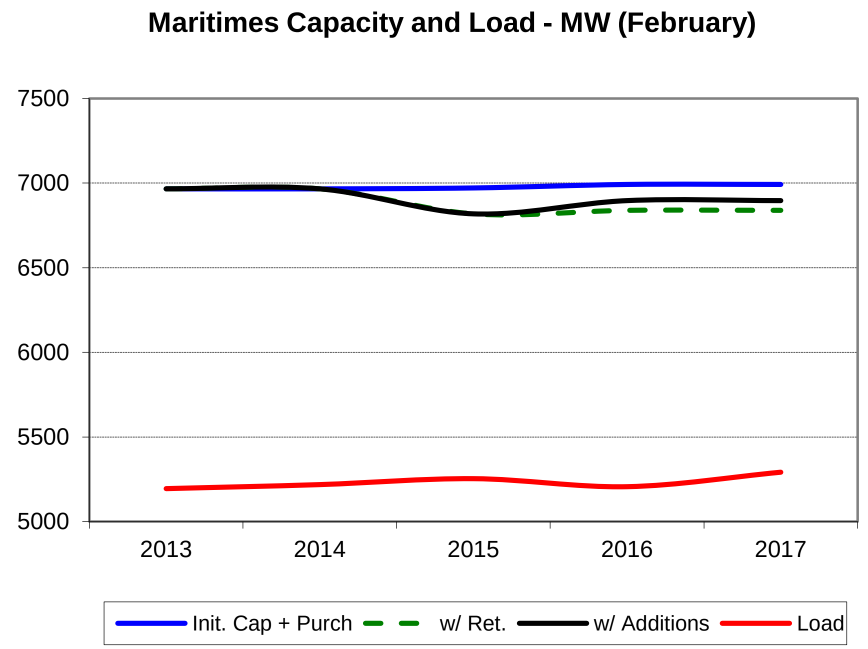

Figure 1 – Maritimes Area Capacity and Load

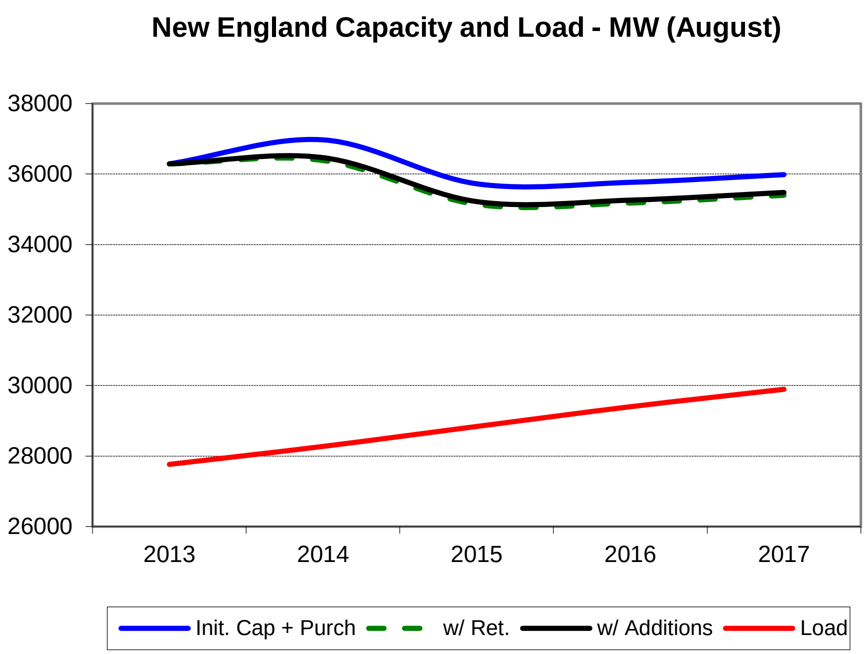

Figure 2 – New England Capacity and Load

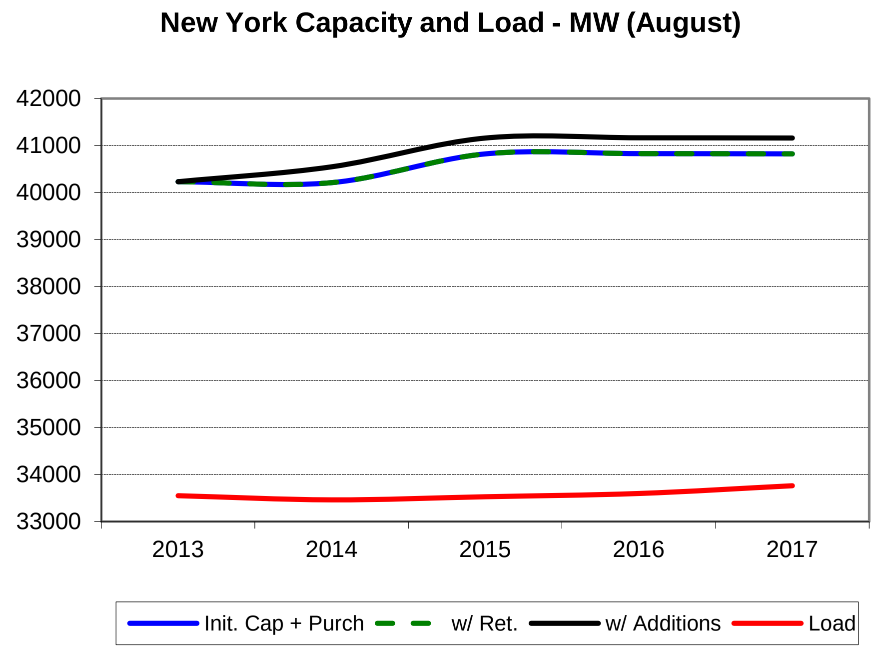

Figure 3 – New York Area Capacity and Load

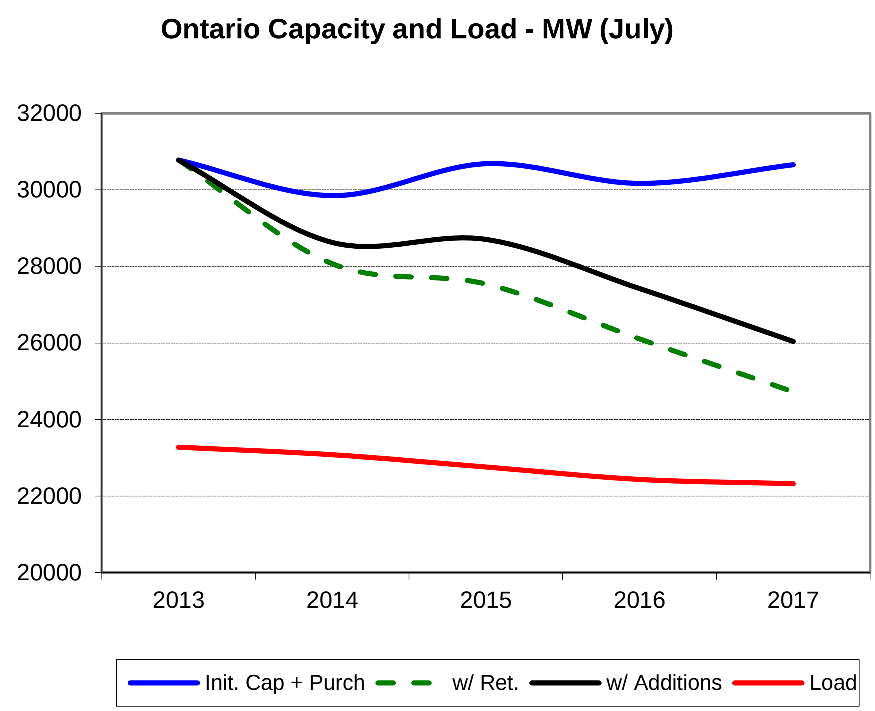

Figure 4 – Ontario Capacity and Load

Quebec Capacity and Load - MW (January)

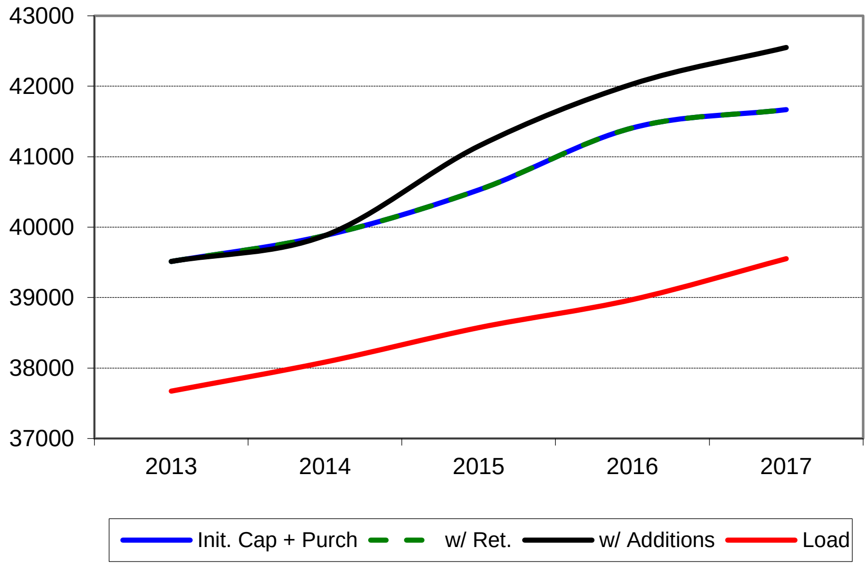

Figure 5 – Québec Capacity and Load

PJM-RTO Capacity and Load - MW (July)

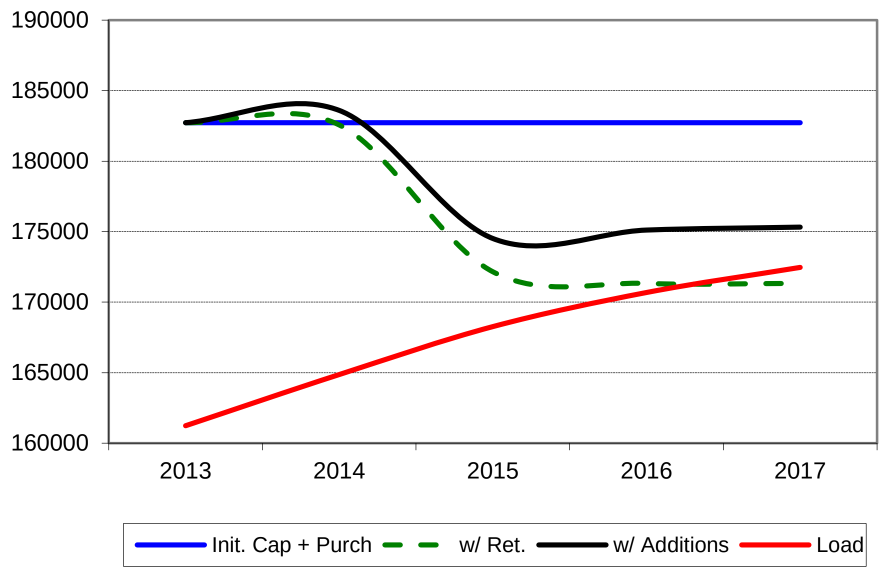

Figure 6 – PJM-RTO Capacity and Load

Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the 2013-2017 time period.

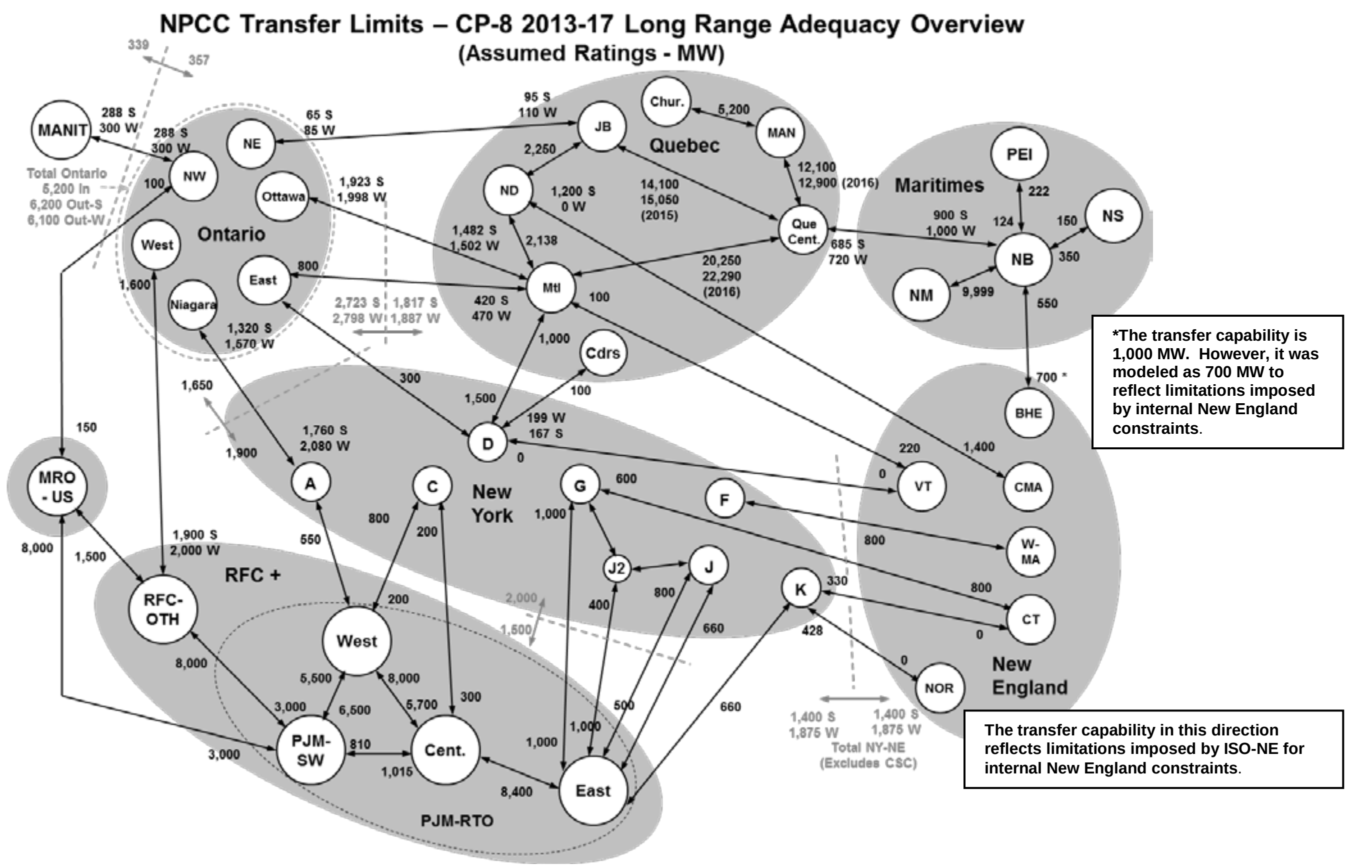

Figure 7 - Assumed Transfer Limits

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. Table 2 summarizes the load relief assumptions modeled for each NPCC area.

Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2013 Load Relief Assumptions - MW

Actions	**MT (Feb)**	**NE (Aug)**	**NY (Aug)**	**ON (July)**	**QC (Jan)**
1. Curtail Load / Utility Surplus	-	-	-	148	1,339
Appeals	-	-	-	1% of load	-
RT-DR/SCR/EDRP	-	875 [15]	1,748	-	-
SCR Load /Man. Volt. Red.	-		0.36% of load	-	-
2. No 30-min Reserves	234	600	765	473	500
3. Voltage Reduction	-	374	1.20% of load	-	250
Interruptible Loads [16]	253	-	-	-	-
4. No 10-min Reserves	660	-	-	1,080	750
RT-EG	-	387 [17]	- -	-	-
General Public Appeals	-	-	213	-	-
5. 5% Voltage Reduction	-	-	-	2.60% of load	-
No 10-min Reserves	-	1,575	1,200	-	-

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

[15] Derated value shown accounts for assumed availability.

[16] Interruptible Loads for the Maritimes area (implemented only for the Area), Voltage Reduction for all others.

[17] Derated value shown accounts for assumed availability.

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.

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.

Assistance Priority

All Areas 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.

AREA ASSUMPTIONS

Maritimes Area

The Maritimes Area is comprised of the Canadian provinces of New Brunswick (NB, Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of the state of Maine, which is radially connected to the New Brunswick power system. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area and the Balancing Authority for the NB, PEI, and northern Maine sub areas. Nova Scotia Power Inc. (NSPI) is the Balancing Authority for Nova Scotia.

Because of the relative size of the Area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high capacity transmission lines but is not dependent on these areas to supply area load. As a result, even with reasonable foreseeable contingencies including load forecast uncertainty, fuel disruptions, and generator and transmission interruptions, the Maritimes Area load is expected to be reliably supplied for the next five years.

Long-term resource evaluations are based on a 20 percent Reserve Margin above the forecast Firm winter peak load. Current and projected Energy Efficiency effects are incorporated directly into the load forecast for each of the areas. For New Brunswick and Prince Edward Island, the responsibility for Demand Side Management (DSM) initiatives including forecasts and verification now belongs to provincial government agencies. In Nova Scotia, the DSM administrator is Efficiency Nova Scotia Corporation (ENSC), a non-government, non-profit organization responsible for developing and implementing Energy Efficiency programs. ENSC retains an evaluation consultant to independently evaluate both process and savings impacts of the programs. Additionally, the Nova Scotia Utility and Review Board retain an independent savings verification consultant to verify the savings reported by the independent evaluation consultant.

Demand

The forecast Compound Annual Growth Rate for peak demand is 0.25 and 0.27 percent for the summer and winter seasons, respectively. This indicates that aggregated growth will be effectively offset by the sum of any DSM projections or load losses included in the sub-area forecasts.

Separate demand and energy forecasts are prepared by each Maritimes Area jurisdiction, 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.

The load forecast for New Brunswick is based on 30-year average of the Heating Degree Days in each month from the winters of 1980-1981 through 2009-2011, with the annual peak hour demand determined for a design temperature of -24°C over a sustained 8-hour period. It is prepared based on a cause and effect analysis of past loads, combined with data gathered through customer surveys, and an assessment of economic, demographic, technological and other factors that affect the utilization of electrical energy.

The load forecast for Nova Scotia is based on analyses of sales history, weather, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

The load forecast for PEI uses an econometric model that factors in the historical relationship between electricity use and economic factors such as gross domestic product, electricity prices, and personal disposable income. The load forecast for northern Maine is based on historic average peak hour demand patterns. Monthly peak forecasts for the Maritimes Area are summations of the individual jurisdiction forecasts. The peak is therefore non-coincident. For Area studies, the individual forecasts are combined using the load shape of each jurisdiction. All jurisdictions in the Maritimes Area are winter peaking due to high electric heating load.

Demand Response

Current and projected Energy Efficiency effects are incorporated directly into the load forecast, while Demand Response is counted as a load modifier. Moreover, Demand Response is not used for peak shaving. It is used to reduce demand during emergencies and is not backed by capacity reserves. Contractually interruptible (curtailable) Demand Response is projected to account for 252 MW in 2013.

Jurisdictions within the Maritimes Area have established Energy Efficiency corporations or government agencies whose mandate is to provide sustainable Energy Efficiency and conservation solutions to customers. Policy drivers include maintaining affordable electricity prices for customers and lessening the impact of energy use on the environment. Additionally, a pilot program called PowerShift Atlantic is developing the capability to utilize load control for Ancillary Services. Launched in 2010 as part of the Clean Energy Fund, PowerShift Atlantic is a collaborative research project led in partnership by New Brunswick Power, Saint John Energy, Maritime Electric, Nova Scotia Power, New Brunswick System Operator, the University of New Brunswick, Natural Resources Canada, the Government of New Brunswick and the Government of Prince Edward Island. This four-year, innovative program will run until 2014, piloting technology that shifts energy supply to specific appliances in homes and commercial buildings in order to optimize wind generation with minimal or no disruption to participating electric utility customers.

Capacity Transactions

Currently there are no Firm capacity imports scheduled in the 2013 -2017 time frame.

The Maritimes Area has projected Firm imports to begin in 2018, from the Newfoundland utility NALCOR. In 2018, development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador includes the installation of a High Voltage Direct Current (HVdc) undersea cable link (Maritime Link).

The Maritimes Area does not depend on emergency imports from other areas to meet its resource adequacy requirements.

Transmission

Major new transmission line additions are in Conceptual stages during the review period. In New Brunswick, a new 345kV circuit between the Coleson Cove and Salisbury terminals is being considered to improve transmission service to southeastern New Brunswick, which has experienced relatively higher load growth compared to the remainder of the province. New Brunswick and Nova Scotia are studying a project to twin the existing 100-mile-long 345 kV transmission line between Salisbury, New Brunswick, and Onslow, Nova Scotia. This project is under study for 2016 and will allow for increased integration of renewable energy in the Maritimes Area.

Conceptual 345 kV line reinforcements from Coleson Cove to Onslow would alleviate existing constraints that limit capacity transfers between New Brunswick and Nova Scotia to non-Firm or short-term transactions (currently projected for the 2016 time frame – further study will determine its need and timing).

The 2012 retirement of the Dalhousie Plant in NB requires the addition of a new 345 kV breaker at the New Brunswick Belledune terminal to improve local reliability. The plant retirement also made it necessary for the 240 kV terminal at Eel River NB to be reconfigured to allow a single feed to two 240/138 kV parallel transformers to be split. A refurbishment of one of two HVdc stations between the Maritimes Area and Hydro Québec at Eel River New Brunswick is being tentatively planned for 2014. A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick. This will help maintain voltages in the area during contingency conditions. No new circuit miles are involved in any of these projects. The construction periods for the planned projects mentioned above are all of short duration and can be scheduled during times that will not significantly affect the reliability of the area.

Being of small size and spread over a multitude of sites, additions to the generation complement in the Maritimes Area of small wind farms and biomass-fueled projects will not require major transmission reinforcement.

A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick, and a second 36 Mvar capacity bank will be added at Bridgewater in southwest Nova Scotia in 2013. From 2013 to 2017, changes to the HVdc system in the

Maritimes will include the proposed 2014 refurbishment of the 350 MVA Eel River HVdc Station on the New Brunswick tie to Québec.

Generation

As shown in Table 3, the primary sources of fuel in the Maritimes Area are oil and coal, followed by hydro, natural gas, and nuclear. Other capacity sources include wind and biomass.

Table 3
Maritimes Current Capacity [18]

NPCC-Maritimes-Winter	Current Capacity	Current Share
Coal	1,714	25.0%
Petroleum	1,857	27.1%
Gas	829	12.1%
Nuclear	660	9.6%
Other/Unknown	0	0.0%
Renewables	1,796	26.2%
TOTAL	**6,856**	**100.0%**

Since 2011, 49 MW of Existing-Certain capacity fueled by existing natural gas units in combined-cycle mode was added at Nova Scotia's Tufts Cove plant. Another 40 MW of wind generation capacity derated to 14 MW of Existing-Certain capacity was installed at two sites.

The return to service of the 660 MW Point Lepreau Nuclear Generating Station was a major Future-Planned capacity addition during 2012. There are no Conceptual projects planned during this assessment period. The retirement of the 299 MW oil-fired Dalhousie Plant in New Brunswick occurred May 31, 2012. The capacity reduction has been more than offset by the return to service of the 660 MW Point Lepreau Nuclear Generating Station.

The refurbishment of the Point Lepreau Nuclear Generating Station results in a 25 MW uprate of the plant's net capacity. This small uprate has no significant long-term reliability impact.

The impact of the assumed retirement of one of Nova Scotia's fossil fueled generators in 2015 is expected to be offset by installation of wind and biomass units.

There are no significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia. Existing distributed resources are netted against load and not counted as capacity.

The Maritimes Area has no non-traditional (e.g., storage, flywheels, batteries) resources. Wind projects included with capacities modeled in resource adequacy calculations for New Brunswick and northern Maine (40 percent of nominal capacity during the winter

[18] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

peak period) are based on results from the September 2005 NBSO report "Maritimes Wind Integration Study." [19] This report showed that the effective capacity from wind projects and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors.

The Maritimes Area projects no solar power installations. With very few small exceptions, hydro and biomass generators are not derated during peak periods.

Currently, wind generators are accredited with on-peak capacity, based on observed or expected seasonally adjusted capacity factors. Hydro and biomass units are expected to be fully available during peak periods, and on-peak capacity is equal to their demonstrated unit capability (Table 4). The Maritimes Area is currently reviewing and assessing previously used methods for attributing on-peak wind capacity.

Table 4
Maritimes Current Renewable Capacity

	Current			
NPCC-Maritimes-Winter	Wind	Solar	Hydro	Biomass
Installed Capacity	816	0	1,339	148
On-Peak Derate	498	0	2	7
EXPECTED ON-PEAK OUTPUT	318	0	1,337	141

Plans are underway for the individual jurisdictions within the Maritimes Assessment Area to coordinate the sharing of wind data and possibly wind forecasting information and services. With the integration of more variable resources, it may become necessary to curtail these generation levels at light load periods to ensure adequate levels of spinning reserves and inertia for frequency control. The grid codes in the area require the ability to curtail to be designed into the control systems for large-scale variable resources and available for system operators to dispatch accordingly.

New England

ISO New England expects to have adequate resources to satisfy reliability throughout the assessment period. The amount of Anticipated Resources in the 2013 summer is 35,265 MW, and the reference gross demand forecast is 27,765 MW during the summer season.

Resource assumptions used for the assessment reflect Seasonal Claimed Capability (which could be higher than the Capacity Supply Obligation (CSO)) of all ISO-NE generators, as well as demand resources and imports that have assumed CSOs under the ISO-NE's Forward Capacity Market (FCM). Consideration for generator Seasonal Claimed Capabilities has not been included in determining the capacity projections in long-term assessments since 2008, when ISO-NE started to use CSOs in the NERC Long-Term Reliability Assessment (LTRA) to reflect the capacity purchased under the FCM. Prior to the 2008 assessment, all generator capabilities in the LTRA were based on the

[19] http://www.nbso.ca/Public/_private/2005 Percent20Maritime Percent20Wind Percent20Integration Percent20Study Percent20_Final_.pdf.

Seasonal Claimed Capability. The reason for reflecting the generator Seasonal Claimed Capabilities in this and future LTRAs is that when the energy prices are lucrative (which is always the case during annual peak demand conditions), generating resources offer the energy market up to, and sometimes more than, their Seasonal Claimed Capability. The LTRA would undercount New England capacity if ISO-NE only reflected the CSOs in the LTRA.

Resource assumptions for this assessment reflects the Seasonal Claimed Capability of all ISO-NE generators, as well as demand resources and imports that have Capacity Supply Obligations (CSOs) as a result of ISO-NE's Forward Capacity Market (FCM) auctions.

Demand

The 2013 summer peak demand forecast is 27,765 MW, and the Net Internal Demand, which takes into account 1,136 MW of passive demand resources (Energy Efficiency), is 26,629 MW.

This year's forecast of the 10-year summer Total Internal Demand compound annual growth rate (CAGR) based on Total Internal Demand is 1.44 percent, which is slightly higher than the 2011 projection of 1.30 percent. The reason for this increase is changes in the economic forecast.

ISO-NE's reference case demand forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted temperature-humidity index (WTHI) of 79.88, which is equivalent to a dry-bulb temperature of 90.2 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference case demand forecast is based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur.

ISO-NE develops an independent demand forecast for the Balancing Authority area as a whole and the six states within it. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon Revenue Quality Metering (RQM), to develop historical demand data which the regional peak demand and energy forecasts are based upon. From this historical data, ISO-NE develops a forecast of both monthly peak and energy demands by state. The peak demand forecast for the subregion and the states can be considered a coincident peak demand forecast.

Demand Side Management (DSM)

DSM in New England consists of active demand resources and passive demand resources. Active demand resources consist of real-time Demand Response and real-time emergency generation, which can be activated with the implementation of ISO-NE

Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4).[20] Some assets in the real-time Demand Response programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE—for example, interruption of central air conditioning systems in residential and commercial facilities. Passive demand resources (i.e., Energy Efficiency and conservation) include installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours.

The amount of summer active Demand Resources [21] in 2013 is projected to be 1,681 MW and the amount of passive Demand Resources [22] is 1,136 MW. In the winter, the amount of active and passive DR is 1,536 MW and 1,127 MW, respectively (Table 5).

Table 5
New England Demand-Side Management

	Short-Term		
NPCC-New England-Summer	2013	2014	2015
Direct Control Load Management (DCLM)	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	1,681	1,999	1,919
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,681	1,999	1,919
Direct Control Load Management (DCLM)	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	1,136	1,398	1,647
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,136	1,398	1,647
TOTAL ENERGY EFFICIENCY	0	0	0
TOTAL DEMAND-SIDE MANAGEMENT	**2,817**	**3,397**	**3,566**

The active DR is based on the Capacity Supply Obligations (CSO) obtained through ISO-NE's Forward Capacity Market (FCM) three years in advance. The CSOs increase from 1,681 MW in 2013 to 1,999 MW in 2014 and then decrease slightly to 1,919 MW in 2015. At that point, since there are no further auction results, the CSOs are assumed to remain the same through the end of the reporting period.

Energy Efficiency is also secured by means of FCM CSOs. However, this year ISO-New England developed a new Energy Efficiency forecasting methodology that takes into account the potential impact of growing Energy Efficiency (EE)/conservation initiatives in the Region to project the amount of EE beyond the years when the FCM CSOs have

[20] OP-4 (located at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html) is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus Operating Reserve Requirement.

[21] Active Demand Resources in New England are considered Demand Response that is treated as a resource for this assessment.

[22] Passive Demand Resources in New England are treated as load-modifying Demand Response for this assessment.

already been procured. EE has been increasing and is projected to continue growing throughout the study period, but at a continually decreasing rate. The amount of EE in 2013 is 1,136 MW, increasing by 23 percent to 1,398 MW in 2014 and by 18 percent to 1,647 MW in 2015.

Both passive and active demand resources are treated as capacity in New England's FCM. The active demand resources can be triggered by ISO-NE in real time under OP-4 to help mitigate an actual or Anticipated Capacity Deficiency by reducing the peak demand. For example, on July 22, the 2011 peak demand day, a total of 642 MW of active DR was dispatched and 644 MW responded. On another OP-4 occurrence on the morning of December 19, 2011, active DR reduced the load by 380 MW (out of 504 MW dispatched).

Generation

ISO-NE's Existing Certain capacity in summer 2013 is 31,938 MW. Natural gas-fired generation represents the largest component of ISO New England's total installed capacity, followed oil-fired generation, nuclear generation, and coal.

A total of 196 MW of new generation has been installed since the 2011 summer. Most of that capacity consists of a 130 MW gas-fired combustion turbine. In addition, a wind facility with a 62 MW summer rating (217 MW nameplate) went commercial. The on-peak capacity of intermittent generators such as wind, hydro, and solar units is based on actual generation during the summer or winter reliability hours. Therefore, the capacity as a percentage of nameplate varies from resource to resource.

ISO-NE has a total of 184 MW of capacity in the Future-Planned Category, all of which is expected to be in service by summer 2013 and consists primarily of biomass (84 MW), wind (42 MW, with a nameplate capability of 228 MW), landfill gas (28 MW), and fuel cell (18 MW) projects. Conceptual capacity, [23] which is not modeled in this assessment, amounts to a total of 6,037 MW.[24] The queue projects include primarily natural gas (3,734 MW), wind (1,991 MW nameplate), and biomass facilities (159 MW). Hydro-electric uprates, oil-fired peaking units, and solar projects make up the remaining 153 MW (Table 6)

AES Thames, a 181 MW coal plant located in southeastern Connecticut, ceased operation in early 2011. In addition, Salem Harbor units 1 and 2 (158 MW) were shut down as of December 31, 2011, and Salem Harbor Units 3 and 4 (587 MW) are scheduled to retire by June 1, 2014.

[23] All of the capacity in ISO-NE's generator interconnection queue that is not included in the Future-Planned Category.

[24] Includes all Conceptual additions with in-service dates from summer 2012 to summer 2017. Does not include conceptual retirements.

Table 6
New England Current Capacity [25]

NPCC-New England-Summer	Current		
	Capacity	Share	Capacity
Coal	2,484	7.8%	2,176
Petroleum	6,895	21.6%	6,463
Gas	13,772	43.1%	13,790
Nuclear	4,628	14.5%	4,628
Other/Unknown	0	0.0%	0
Renewables	4,191	13.1%	4,352
TOTAL	**31,969**	**100.0%**	**31,410**

The retirements of both AES Thames and Salem Harbor have been included in this assessment. ISO-NE ensures that it has adequate capacity up to three years in advance with its Forward Capacity Auctions and Annual Reconfiguration Auctions. With respect to local loads, there is adequate capacity and transmission within the Connecticut sub-area where AES Thames is located. Since the Salem Harbor plant is located in the Boston sub-area, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. It was found that under certain second contingency scenarios with a 345 kV line-out as the initial outage, thermal overloads could exist in the local area. To address these thermal overloads, ISO-NE and the affected Transmission Owners have developed plans to perform 115 kV transmission line reconductoring projects on portions of five lines prior to the plant retirement. These upgrades are expected to be completed in May 2014.

ISO-NE has small amounts (less than 5 MW total) of non-traditional resources providing regulation service through a pilot program. These include battery storage, flywheels, electric thermal storage heating, and aggregated load control. After the pilot program concludes, these resource types will remain eligible to provide regulation service. There is no current expectation that these resources will or will not participate in the energy and capacity markets in the future. However, technologies with multi-hour storage capability may become economically viable participants in the energy market depending on fuel prices, penetration of renewable resources, and localized transmission congestion.

As of summer 2012, ISO-NE has 97 MW of on-peak wind capacity, with a total nameplate capability of 566 MW. The amount of on-peak solar capacity is 5 MW, with a nameplate capability of 18 MW. For 2013, on-peak hydro-electric capacity is 1,483 MW, derated from a maximum capacity of 2,043 MW, and biomass capacity is 907 MW (Table 7).

[25] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Table 7
New England Current Renewable Capacity

NPCC-New England-Summer	Current Wind	Solar	Hydro	Biomass
Installed Capacity	566	18	2,043	907
On-Peak Derate	469	13	560	0
EXPECTED ON-PEAK OUTPUT	97	5	1,483	907

ISO-NE continues to integrate new power supply sources—including new variable resources—into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. These are all integrated through the use of operating guides/interface limits and through our Energy Management System (EMS). To facilitate system operation with potentially large amounts of wind power, ISO-NE Operating Procedure No. 14 [26] was developed and implemented. OP-14 is chiefly concerned with requirements for real-time and static-type data that will facilitate accurate wind power forecasting over the intra-day, day-ahead, and week-ahead timescales, as well as data for use in situational awareness functions for ISO system operators.

Capacity Transactions

Firm summer capacity imports increase from 1,746 MW in 2013 to 1,768 MW in 2015 before eventually falling to 95 MW in 2017. The capacity imports for those years reflect the results of the appropriate FCAs. Since the FCA imports are based on one-year contracts, beginning in 2016 the imports reflect only known, long-term ICAP contracts. If the imports beyond the 2015 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or Demand-Side resources.

Transmission

The ISO New England 2012 Regional System Plan has identified projects that address transmission system performance issues, either individually or in combination. Some of the projects, as described below, address local reliability issues and also have the ancillary benefit of improving the performance of major transmission corridors and thus the overall performance of the system.

There are several transmission projects that are projected to come on-line during the assessment period that are important to the continuation of, or enhancement to, system or sub-area reliability. These projects are the results of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England, developing back-stop solutions to address existing and projected transmission system needs, and implementing these solutions.

[26] Appendix F – Wind Plant Operators Guide (OP-14F): http://www.iso-ne.com/rules_proceds/operating/isone/op14/.

The major projects under development in New England include the Maine Power Reliability Program (MPRP), the New England East-West Solution (NEEWS), and the Long-Term Lower SEMA project. The new paths that are part of MPRP, many components of which are under construction, will provide basic infrastructure necessary to increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the local load pockets as necessary. NEEWS consists of a series of projects that have been identified to improve system reliability, including in Springfield and Rhode Island, and increases total transfer capability across the New England east-to-west and west-to-east interfaces. The Long-Term Lower SEMA project eliminates the criteria violations in the lower southeastern Massachusetts Area, which includes Cape Cod.

Currently, there are no transmission constraints preventing the system from being operated in a manner that ensures the reliability of the New England-wide system. The proposed projects with the target in-service dates are expected to enhance the long-term reliability of the New England bulk power supply system. There are no major interconnection-related projects or issues at this time.

Presently there are no significant concerns over meeting the target in-service dates of any of the transmission projects. However, if the implementation of these projects is delayed, interim measures will be taken, such as issuing gap requests for proposals (RFPs) to install temporary generation in a specific area of the system.

No additional significant substation equipment such as SVC, FACTS controllers, or HVdc is currently planned to be added to the system.

New York

The New York Balancing Authority (NYBA) is projecting adequate Planning Reserve Margins based upon the current NYBA Installed Reserve Margin. The Installed Reserve Margin (IRM) requirement for the NYBA Area that covers the period from May 2012 to April 2013 (2012 Capability Year) is 16 percent. This requirement is based upon an annual study conducted by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS).

New York State is considering a number of environmental initiatives under the Federal Clean Air Act, Clean Water Act and the New York State Environmental Conservation Law that could affect the availability of generation resources in New York and may lead to generator retirements. The NYISO monitors these regulatory initiatives and analyzes their potential reliability impact through its Reliability Planning Process, which is primarily comprised of a biennial Reliability Needs Assessment (RNA) and a Comprehensive Reliability Plan (CRP). At this time there are no environmental or regulatory restrictions that adversely impact reliability during the time-frame of the assessment.

The NYISO's Reliability Planning Process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over 10-year planning horizons to ensure that the New York State bulk power system meets or exceeds the planned loss of load expectation (LOLE) that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10-years, or 0.1 days per year. Results of the 2010 RNA, published September 2010, [27] demonstrate that the LOLE for the New York Balancing Area (NYBA) does not exceed 0.1 days per year in any year through 2020 under Base Case conditions.

Demand

Last year's forecast compound average growth rate (CAGR) was 0.66 percent (from 2012 to 2021), compared to 0.81 percent for this assessment period (2013-2022).

The primary differences between the forecasts are the recovery from the recession in the short term as well as a reduction in the estimate of peak demand associated with Energy Efficiency programs.

The NYISO develops independent forecasts for each of 11 zones in its control area; the total is based on the sum of the zones. Both coincident and non-coincident peak demands are forecast. The peak producing conditions are based upon the 50th percentile for most regions of the state. However, in certain regions in and around New York City, the peak-producing conditions are more conservative, based upon the 67th percentile. This provides additional reliability for this part of the control area. As a result, the statewide forecast is somewhat higher than a 50th percentile. The weather assumptions and economic assumptions for the 50-50 forecast are normal weather and an eventual recovery from the recession.

Both the current and the previous forecasts have incorporated reductions in peak demand expected to be achieved by statewide Energy Efficiency programs. These programs are funded by the state of New York through system benefits charges applied to all retail rates. The programs are implemented by the New York State Energy Research and Development Agency, the major investor-owned utilities in the state, and by other state power authorities, such as the Long Island Power Authority and the New York Power Authority.

The New York State Public Service Commission (NYS PSC) has ordered the creation of an Evaluation Advisory Group to develop statewide standards for the measurement and verification (M & V) of the impacts of the programs, after they are installed. This group is currently developing M & V protocols that will be followed by program implementers.

[27] See: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp

Monthly program tracking results are provided to the Department of Public Service staff to determine whether program activities are meeting the goals set by the state.

Demand Side Management

Demand Response resources expected to be available on-peak for the first year of the assessment include 2,165 MW (summer 2013) of Special Case Resources and 257 MW (summer 2013) of Emergency Demand Response Program (EDRP) resources. These numbers are reported in the "2012 Load and Capacity Data Report." [28] The 2013 forecast of peak demand impact of Energy Efficiency programs is 343 MW (Table 8).

The Demand Response resources are held constant over the 10-year assessment period of the NERC LTRA. The cumulative forecast Energy Efficiency impact on peak demand is 1,674 MW by 2017. The growth of peak demand impact is 650 MW during the second five years of the forecast.

Table 8
New York Demand-Side Management

	Short-Term		
NPCC-New York-Summer	2013	2014	2015
Direct Control Load Management (DCLM)	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	2,165	2,165	2,165
TOTAL RESOURCE-SIDE DEMAND RESPONSE	2,165	2,165	2,165
TOTAL ENERGY EFFICIENCY	624	932	1,210
TOTAL DEMAND-SIDE MANAGEMENT	**2,789**	**3,097**	**3,375**

The projected levels of Demand Response resources are held constant beyond 2013. The inclusion of Special Case Resources in this manner is an appropriate assumption for planning purposes as these resources can be added or removed with short lead times and are driven by market conditions.

No significant developments or policy implementations are known at this time.

The NYBA's market rules allow for aggregations of demand side resources to provide operating reserves and regulation service.

The New York Independent System Operator, Inc. offers two reliability-based Demand Response programs: the Emergency Demand Response Program (EDRP) and the Installed Capacity-Special Case Resource Program (ICAP/SCR). Resources may register for either EDRP or ICAP/SCR, but not both programs during the same capability month; however, resources enrolled in the ICAP/SCR program that have not sold capacity for the month may participate in an EDRP activation occurring in that same month.

[28] http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

EDRP, which also includes the Targeted Demand Response Programs discussed below, provides demand resources with the opportunity to earn the greater of $500/MWh or the prevailing location-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on the resource. There are no consequences for enrolled EDRP resources that fail to curtail. Resources participate in EDRP through Curtailment Service Providers (CSP), which serve as the interface between the NYISO and resources.

The Targeted Demand Response Program (TDRP), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources that have not sold capacity for that month on a voluntary basis, at the request of a Transmission Owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City. Responding resources are eligible for an energy payment during the event, using the same performance calculation as EDRP resources.

The ICAP/SCR program allows demand resources that meet certification requirements to offer Unforced Capacity (UCAP) to Load Serving Entities (LSE). Special Case Resources can participate in the Installed Capacity (ICAP) Market just like any other ICAP Resource; however, Special Case Resources (SCRs) participate through Responsible Interface Parties, which serve as the interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two or more hours' notice, provided the NYISO notifies the Responsible Interface Party day ahead of the possibility of such a call. In addition, ICAP/SCR resources are subject to testing each capability period to verify that they can fulfill their curtailment requirement. Failure to curtail could result in penalties administered under the ICAP program. Curtailments are called by the NYISO when reserve shortages are anticipated. Special Case Resources are eligible for an energy payment during an event, using the same performance calculation as EDRP resources.

Load reductions for energy payment are determined by comparing the actual metered load during the event or test to an estimate of what the load would have been without the event or test. This method is commonly known as a CBL or Customer Baseline Load method. The energy CBL used by the NYISO is based on the hourly average of the highest five out of the last ten similar days with adjustments for weather permitted.

The NYISO also calculates a capacity performance factor for SCRs. The calculation compares the committed demand level to the metered value during the event or test. The calculated performance factor is used to determine the UCAP that is available from each resource for each Capability Period.

Generation

The NYBA Area currently enjoys a diverse fuel supply (Table 9). Since the last reporting year, new resources totaling 633 MW have come on-line. These include 549 MW of natural gas, 52 MW of wind, and 32 MW of solar. Additionally, there are 182

MW of unit uprates scheduled for 2012. The most significant generator uprate is the 168 MW uprate of a nuclear facility. The NYBA expects the reliance on natural gas as the fuel for new generation to increase over time, and that fuel diversity will decrease as a result.

No current Future-Planned resources are confirmed to come on-line during the assessment period at this time. There are a total of 2,537 MW of Conceptual resources in the NYISO interconnection queue that are at various stages of study that may come on-line over the assessment period. These include 2,198 MW of natural gas, 312 MW of nameplate wind capacity, 21 MW of biomass, and 6 MW of hydro-electric resources.

There are a significant number of generators retiring/mothballing that are impacting the NYBA Area this year. Since last year, 1,804 MW of generator retirement/mothball notices have been received. 88 MW of generation retired in 2011. The remaining 1,716 MW are scheduled to retire/mothball during 2012.

Table 9
New York Current Capacity [29]

NPCC-New York-Summer	Current Capacity	Current Share
Coal	2,370	6.4%
Petroleum	9,152	24.8%
Gas	14,133	38.3%
Nuclear	5,431	14.7%
Other/Unknown	0	0.0%
Renewables	5,771	15.7%
TOTAL	**36,858**	**100.0%**

When the NYISO receives a generator retirement/mothball notice, the NYISO conducts an impact study to determine if reliability issues will arise when the unit shuts down. If no need is determined, then the unit may retire/mothball as planned. However, if a need is determined to exist, follow-up studies are required. If the need is on the local transmission system, the local transmission owner is required to resolve the reliability need. The solution may be that the unit remains on-line as a must-run unit for reliability. If the local transmission owner provides a solution to maintain reliability, the unit may then retire/mothball as planned, providing that the solution is in place prior to the retirement/mothballing date. If the solution will not be in place per the unit's shutdown schedule, the unit may be required to remain in service until the transmission owner's solution is fully implemented. The NYISO would determine the course of action in consultation with the NYS PSC and NYISO stakeholders. Following implementation of the solution, the unit may then enter the retired/mothballed status.

If the Reliability Need is determined to be on the BPS, the NYISO's Comprehensive System Planning Process (CSPP) will study the need in detail as part of the development of NYISO's Comprehensive Reliability Plan (CRP). If the Reliability Needs Assessment

[29] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

(RNA) identifies any violation of Reliability Criteria for bulk power transmission facilities, the NYISO will report a Reliability Need, quantified by an amount of compensatory megawatts or Mvars, and designate one or more Responsible Transmission Owners to develop a regulated backstop solution to address each identified need. In addition, after approval of the RNA, the NYISO will request market-based and alternative regulated proposals from interested parties to address the identified Reliability Need.

Proposed solutions that are submitted in response to an indentified Reliability Need are evaluated in the CRP process and must satisfy Reliability Criteria, including resource adequacy and system security. However, the solutions submitted to the NYISO for evaluation in the CRP do not have to be in the same amounts of compensatory MW/Mvar or the locations reported in the RNA. There are various combinations of resources and transmission upgrades that could meet the needs identified in the RNA. The reconfiguration of transmission facilities and/or modifications to operating protocols identified in the solution phase could result in changes and/or modifications of the needs identified in the RNA.

There is only one significant generator uprate occurring over the assessment period. The Nine-Mile nuclear facility will uprate by 168 MW. This will generally have a positive impact on system reliability as nuclear units typically have a very low forced outage rate and scheduled refueling outages are outside peak demand times. The impact will be more noticeable on the operational side as the rated summer capability after the uprate will be 1,309 MW. This exceeds the current 1,200 MW single contingency loss that has been in place for operating reasons and has required that the system carry 1,800 MW of reserves (600 MW 10-minute sync, 600 MW 10-minute non-sync, and 600 MW 30-minute). Operating procedures have been updated to increase the amount of reserves the NYBA carries when the uprate goes into service.

The NYBA neither plans for nor relies on behind-the-meter generation for reliability purposes except for those resources that opt to participate in one of the NYBA's Demand Response Programs.

There are only two "non-traditional" resources in the NYBA's markets. A 20 MW flywheel and an 8 MW storage battery are listed in the 2012 Gold Book [30]. There is no impact over the assessment period.

The assumed capacity on-peak for variable resources such as wind, solar, and run-of-river hydro included in this assessment is determined using an expected capability for each resource class based upon unit historic operating data and engineering judgment. On-peak land-based wind resources are rated at 131 MW (nameplate capacity of 1,314 MW). On-peak solar resources are expected at 3 MW (nameplate capacity of 32 MW). On-peak

[30] See: http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2012_Gold Book.pdf

run-of-river hydro resources are expected at 3,827 MW. Biomass landfill gas resources are expected on-peak with a rated capacity of 403 MW (Table 10).

Table 10
New York Current Renewable Capacity [31]

	Current			
NPCC-New York-Summer	Wind	Solar	Hydro	Biomass
Installed Capacity	1,311	32	4,282	403
On-Peak Derate	1,180	28	454	0
EXPECTED ON-PEAK OUTPUT	131	3	3,827	403

Hourly unit output data is collected for the summer peak hours (2–5 PM) over the June 1 through August 31 period. A derating factor is then calculated for each resource. The unit-specific capacity factors calculated are used in the NYISO's capacity markets and energy markets. However, for reliability studies and planning assessments a more conservative approach is used. Wind resources are assumed to operate at approximately a 10 percent capacity factor and solar resources are expected to operate at a 65 percent capacity factor. Run-of-river hydro resources are given an assumed derate factor of 45 percent to account for the uncertainty in the amount of water available at peak. Biomass and landfill gas resources are modeled with the unit's rated capability and an associated forced outage rate.

Capacity Transactions

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYBA locality where a minimum amount of Installed Capacity must be maintained. Three such projects are currently in service with a total transmission capability of 1,290 MW. A fourth project (660 MW transmission capability with 320 MW Firm capacity rights) is scheduled to be in service for May 2013. Capacity transactions associated with a UDR are considered confidential market data. Only net capacity import/export totals can be provided to maintain market confidentiality.

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring control areas allowed without violating the LOLE criteria. Firm imports decline slightly from 2,270 MW in 2013 to 2,220 MW in 2017 while expected imports remain unchanged at 1,353 MMW throughout the assessment period (Table 11). Except for grandfathered contracts, these Import Rights are allocated on a first-come, first-serve basis with a monthly obligation. While capacity purchases are not required to have accompanying Firm transmission, adequate external transmission rights must be available to assure delivery to the NYBA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual

[31] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Table 11

New York Projected Capacity Transactions

NPCC-New York-Summer	2013	2014	2015	2016	2017
Expected Imports	1,353	1,353	1,353	1,353	1,353
Firm Imports	2,270	2,220	2,220	2,220	2,220
TOTAL IMPORTS	3,623	3,573	3,573	3,573	3,573
Expected Exports	0	0	0	0	0
Firm Exports	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**3,623**	**3,573**	**3,573**	**3,573**	**3,573**

Only Firm contracts longer than one year are considered in planning studies and reliability assessments. These are reviewed annually in the preparation of the annual Gold Book publication.

Only the known duration of any Firm contracts of at least one year are considered in planning studies and reliability assessments.

The NYBA does not rely on emergency imports to maintain reliability. However, transfer capability is reserved on the ties with our neighbors in our planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency. These imports would be external to the NYBA.

Transmission

The Hudson Transmission Project (HTP) is a new tie-line between PJM and NYISO from PSE&G's Bergen 230 kV substation to ConEdison's W. 49th Street 345 kV Station. The project consists of a back-to-back HVdc converter in New Jersey with a submarine 345 kV ac cable from the converter station to New York City. The project will be capable of transferring 660 MW but has Firm capacity withdrawal rights from PJM of 320 MW. The project is currently under construction with a planned in-service date of May 2013. Additional local transmission owner plans include sub-transmission system reinforcements throughout the state.

Historically the most congested transmission paths in New York are Central East, Leeds–Pleasant Valley, and Dunwoodie–Shore Road. Central East and Leeds–Pleasant Valley constraints are driven by demands in the Lower Hudson Valley resulting in high transfers of power from Upstate New York to New York City. The Dunwoodie–Shore Road constraint is driven by Long Island demand. These constraints could be mitigated through additional transmission, generation, or demand reduction.

There are no project delays or temporary service outages for any transmission facilities that will impact long-term reliability during the assessment period.

The NYISO Minimum Interconnection Standard provides that sufficient transmission is constructed to provide reliable access by any given proposed generation project to the New York State Transmission System. In addition, any generation developer seeking to qualify as an Installed Capacity Supplier must meet the NYISO Deliverability Interconnection Standard, which may require the construction of transmission.

The NYISO's role in the interconnection process is that of process administrator, project and system evaluator, and arbiter to ensure that the Project Developer and Transmission Owner collaborate in good faith to keep the project moving forward in a non-discriminatory manner. The process includes the identification and cost allocation of system upgrades necessary for the safe and reliable interconnection to the BPS. This process includes:

- Interconnection Request submission, review, validation and approval;
- Scoping of project, including NYISO receipt of necessary technical data for each;
- Scoping of Feasibility Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Feasibility Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of System Reliability Impact Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting System Reliability Impact Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of Facilities Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Class Year Facilities Study(ies) with system facilities upgrades and capacity deliverability cost allocation, with final report meeting with Developer and Transmission Owner;
- Submission and approval of Class Year Facilities Study(ies) to NYISO Market Participant governance working groups, sub-committees and Operating Committee;
- Decisions of Project Developers to accept or not accept their Project Cost Allocations for system upgrades; and,
- Interconnection Agreements provided to Developer, including proof of continued site control and the achievement of development milestones, to be filed with FERC.

As part of the DOE Smart Grid Investment Grant, 888 Mvar of smart grid-enabled capacitor banks will be installed at various sub-transmission voltage levels throughout the state by the end of 2012, and 39 phasor measurement units (PMUs) will be installed at bulk power stations throughout New York by June 2013.

Ontario

Ontario is projecting adequate Planning Reserve Margins throughout the assessment period. The required reserve levels were determined based on probabilistic methods in accordance with meeting NPCCs's Loss of Load Expectation (LOLE) criteria. The target Reserve Margin levels for the first four years vary from 19.7 percent in 2013 to 19.2 percent in 2016.

Demand

This year's electricity Net Energy for Load forecast net of conservation has an average annual growth rate of -0.3 percent over the period 2012-2022 compared to last year's average growth of -0.1 percent for the years 2011-2021. The rate of growth for overall consumption is lower than the peak growth rates. Initially conservation was aimed at reducing peaks, but as those peak reduction opportunities are realized, conservation and embedded generation will start impacting overall energy demand. Peak demand for the summer season grows by only 0.7 percent between 2013 and 2022.

With the underlying drivers being very similar to last year, the forecasts' growth rates remain similar as well. Although Canada is expected to post respectable growth over the forecast, Ontario will lag the nation's growth in the near term. High commodity prices—in particular oil—will benefit other parts of Canada over Ontario's manufacturing and export-based economy. In fact, Canada's oil wealth puts upward pressure on the dollar, which is more detrimental to central Canada.

Over the forecast horizon Ontario's economy will continue to undergo structural change. As the economy matures, there is a transition from an energy-intense industrial process based economy to one with a larger service sector and specialized or high-value-added manufacturing. This will lead to a less energy-intense economy.

The forecasting methodology has not changed since last year's forecast. The models have been updated and re-estimated to incorporate the latest information regarding the relationship between electricity demand and the economy, demographics, and weather.

Ontario's forecast of demand is based on Monthly Normal (50/50) weather. The economic forecast is based on the most recent available information and predicts modest but stable economic growth. Electricity demand is expected to lag the general economic recovery as Ontario's economy continues to evolve and mature. This economic evolution has led to a decline in importance of large energy consuming sectors of the economy such as primary industries and manufacturing, to less energy-intense activities like financial services, technology and multimedia. Given a lower and slower rate of underlying growth, Conservation savings and increasing embedded generation capacity are expected to more than offset the electricity demand growth fuelled by economic expansion and population growth. The IESO's reliability analysis is based on this demand forecast.

The forecast of Ontario peak demand is the system peak demand and therefore represents the coincident peak demand of Ontario's 10 main sub-areas or zones. All analysis is done on the system peak demand.

Demand-Side Management

The IESO treats Demand Response as a resource and conservation as a decrement to demand. In 2013 there is just over 1,500 MW of effective Demand Response Capacity available during peak periods. At the time of the 2013 peak, conservation impact is estimated to be roughly 500 MW higher when compared to 2012 (Table 12).

Table 12
Ontario Projected Demand-Side Management

	Short-Term		
NPCC-Ontario-Summer	2013	2014	2015
Direct Control Load Management (DCLM)	0	0	0
Contractually Interruptible (Curtailable)	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	1,529	1,665	1,668
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,529	1,665	1,668
TOTAL ENERGY EFFICIENCY	793	1,285	1,734
TOTAL DEMAND-SIDE MANAGEMENT	**2,322**	**2,950**	**3,402**

The growth in Demand Response is relatively small over the forecast but plateaus in 2015–16.

Demand Response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (e.g., voluntary/Firm contracts). The OPA manages contracts for the majority of the Demand Response programs scheduled to be activated over the forecast time frame. Programs with Firm contracts to reduce demand during periods of high demand/tight supply are expected to provide a reliable and verifiable supply resource. Most Demand Response programs are market-based and are triggered by market prices or supply cushion conditions.

Energy Efficiency and conservation are decremented from demand. These programs are run and delivered by distributors and the OPA. As well, changing efficiency standards and building codes also contribute to conservation savings. The savings are projected to grow throughout the forecast.

The capacity of Demand Response programs is relatively static throughout the forecast, with only some small incremental growth.

Generation

At the time of this assessment in 2012, the total Existing-Certain Capacity Resources connected to the IESO-controlled grid is 29,500 MW. The Existing-Other and Existing-Inoperable capacity amounts to 4,800 MW and 28 MW, respectively.

The primary sources of fuel in Ontario are nuclear, gas or oil, water, and coal (Table 13). More than 50 percent of the electrical energy is generated with nuclear. Coal-fired generation will cease operation by the end of 2014. More than 5,600 MW of gas-fired generation has been added over the last 10 years. About 1,500 MW of grid-connected wind is in operation, with another 200 MW in final stages of commissioning. Future-Planned projections indicate an increase in renewable capacity, to 7,011 MW by 2022.

Table 13
Ontario Current Capacity Outlook[32]

NPCC-Ontario-Summer	Current Capacity	Current Share
Coal	3,377	11.2%
Petroleum	2,148	7.1%
Gas	6,439	21.4%
Nuclear	12,011	39.9%
Other/Unknown	0	0.0%
Renewables	6,156	20.4%
TOTAL	**30,131**	**100.0%**

Since last year, 227 MW of wind and 438 MW of gas generation have come into service. There are 8,782 MW of Future-Planned and Conceptual renewables resources that are expected to come on-line throughout the assessment time frame. Of this, about 200 MW are expected to come from the coal to biomass conversion at the Atikokan Generating Station, which is expected to take place by 2014. The remaining new capacity is mostly comprised of generation from the Feed-In Tariff (FIT) and microFIT programs, and from the Green Energy Investment Agreement. The Future-Planned and Conceptual renewable resources will meet the Government of Ontario's target of 10,700 MW of renewables other than hydro-electric and 9,000 MW of hydro-electric capacity by 2018. Two units at Bruce A Nuclear Generating Station are being refurbished and are expected to add 1,500 MW. In the latter half of the 10-year period, a number of nuclear units at Bruce and Darlington Nuclear Generating Stations will be expected to undergo refurbishment.

Two more coal units at Nanticoke Generating Station with a total capacity of 980 MW were shut down in December 2011. The remaining nine coal-fired units across four facilities in the province will be phased out by 2014. Pickering Nuclear Generating Station is scheduled for retirement by 2016, but the technical feasibility of extending the operating life of the Pickering generating units is being studied with a decision expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating Station through to 2020. In September 2011, a 280 MW gas plant under construction in Mississauga was cancelled. This project had been scheduled to be in service by the third quarter of 2014. There is work currently underway to determine relocation options for this plant. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

By 2014, all coal-fired energy in the province will be phased out. Plans are moving forward for the conversion to biomass of the 205 MW Atikokan Generation Station in northwestern Ontario. In addition, two units at the Thunder Bay Generating Station in northwestern Ontario are candidates for conversion to natural gas over the period leading up to 2014. Conversion of some or all of the remaining coal-fired units at Lambton and

[32] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Nanticoke to natural gas will be assessed, in conjunction with other options, under a range of different scenarios.

Ontario Power Generation's Lower Mattagami expansion project, which is currently under construction, will add 438 MW of hydro-electric capacity to Ontario's electricity system. In addition, by 2013 the new Niagara Tunnel will allow OPG to generate a further 1.6 billion kilowatt-hours of electricity annually.

About 1,500 MW of nuclear capacity is expected to be brought back into service from the re-start of units 1 and 2 at Bruce A Nuclear Generating Station in the short term. In the years following the 2014 coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. The technical feasibility of extending the operating life of the units at Pickering Nuclear Generating Station is being studied, and an update is expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating System through to 2020. Units at Bruce B and Darlington Nuclear Generating Station are expected to reach the end of their service lives over the next decade. To extend their lives, these units will be taken out of service for refurbishment. Supply options for maintaining resource adequacy over this time period are under review and include, among others, new gas generation or conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas.

Over the assessment time frame, the level of renewables penetration will be expected to increase significantly through the FIT and microFIT programs. This in turn will increase the level of behind-the-meter generation. Much of this generation could be variable in nature, which adds more volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system. The majority of distribution-connected generation is expected to be solar, with lesser amounts of wind.

While a vast number of storage technologies are available for development, five are particularly promising and are being developed by companies within Ontario. These include batteries, pumped hydro, compressed air energy storage (CAES), flywheels and hydrogen storage. While most of these technologies are only recently seeing major development for grid applications, some technologies have a long history in the province, such as hydro-electric pumped storage at the Sir Adam Beck Pump Generating Station in Niagara Falls.

While all these technologies offer energy storage, each provides its own specific utility to the grid. Short-term storage systems that can supply power for less than two minutes are generally used for frequency regulation and to maintain grid power quality. Technologies such as batteries and larger flywheels can supply medium-term storage providing frequency regulation and ramping capabilities and can help improve system reliability. Long-term supply can be provided from technologies such as pumped hydro, CAES, hydrogen and some battery technologies that are capable of lasting more than one hour. These solutions among others can be used to increase grid capacity, offering Firm output. Energy storage can also defer transmission and distribution system upgrades if installed in the right location.

As renewables make up an increasingly large portion of the supply, energy storage systems can address some of the problems caused by the intermittent nature of some renewable energy sources, such as wind and solar.

Fourteen percent of the installed wind capacity is assumed to be available at the time of summer peak, and 32 percent is assumed to be available at the time of winter peak. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data and the simulated 10-year historic wind data will continue until 10 years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation. The WCC values are updated annually.

Ontario's solar capacity value is forecast to be 30 percent of installed for the summer peak and 4 percent contribution for the winter peak. The difference is due to the fact that the summer peak occurs in the afternoon, whereas the winter peak occurs in the evening around dinner time. The values are based on historical modeled photovoltaic output data at the time of summer and winter peaks. The renewable capacity outlook is included in Table 14.

On average, the assumed capacity contribution for biomass generation ranges from 64 to 98 percent of installed capacity. Hydro-electric generation output forecast is based on median historical values of hydro-electric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Market data starting from May 2002 is used, with new values calculated annually as additional years of market experience are acquired. The assumed capacity contributions for hydroelectric is 71 percent in the summer and 75 percent for the winter.

The hydro-electric forecast may be adjusted to account for the impact of project-related long-duration outages that occur less frequently than regular maintenance. The hydro-electric performance is monitored on a monthly basis, and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months. The project-related long-duration outages may include hydro facility expansions and major equipment replacements and/or repairs.

Table 14

Ontario Renewable Capacity Outlook [33]

	Current			
NPCC-Ontario-Summer	Wind	Solar	Hydro	Biomass
Installed Capacity	1,725	0	7,832	47
On-Peak Derate	1,498	0	2,038	4
EXPECTED ON-PEAK OUTPUT	227	0	5,794	43

Centralized forecasting for variable resources such as solar and wind is an initiative designed to allow for better forecasting of energy production to ensure a more accurate unit commitment occurs. A centralized forecast is being developed for all grid-connected variable resources with a full implementation set to be complete by the first quarter of 2013. Forecasting for embedded variable resources will be developed in 2013. Additionally, the IESO's Renewable Integration Initiative (RII) will facilitate the dispatching of renewable energy, with implementation expected in the fourth quarter of 2013. Variable generation dispatch will allow for greater flexibility and help alleviate occurrences of surplus base-load generation.

Capacity Transactions

No Firm imports into Ontario, exports to other Regions or emergency generation are considered in this assessment. However, for use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group, which includes PJM, NYISO, ISO-NE, and New Brunswick.

Transmission

A new 110 mile 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) was officially declared in service in June 2012. This new line was built to accommodate the output of all eight generating units at the Bruce complex together with approximately 500 MW of existing wind generating capacity, as well as a further 1,200 MW of new renewable generating capacity that is forecast for development within the area. With the new generating facilities, the combined generation in the Bruce Area is projected to exceed 8,100 MW. New dynamic voltage control facilities at Nanticoke and Detweiler will improve the transfer capability from the Bruce Area.

The existing Bruce SPS will be enhanced not only to accommodate the two new 500 kV circuits between the Bruce complex and Milton SS, but also to address other contingency conditions not previously covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during transmission element outage conditions while also assisting with the re-preparation of the system following a permanent fault when subsequent contingency conditions may

[33] Note: The table above shows only the expected grid-connected renewable generation resources in Ontario. A substantial amount of renewable generation is embedded and is included in the demand forecast. About 9 percent of wind, 28 percent of biomass and 81 percent of solar are expected to be embedded in the distribution networks.

become more critical. This SPS will be a permanent feature to deal with planned outages and is not intended for normal operations or to avoid or delay the construction of bulk transmission facilities. The enhanced system was approved by NPCC in spring of 2012 and was placed in service in the second quarter.

To coincide with the completion of the new Bruce to Milton 500 kV line, a 350 Mvar SVC was installed at Nanticoke SS, connected to the 500 kV busbar, and another 350 Mvar SVC was installed at Detweiler TS, connected to the 230 kV busbar. These SVCs were required to provide dynamic reactive support following a critical double-circuit contingency involving either of the 500 kV lines between the Bruce complex and Milton SS.

Four phase angle regulators (PARs) are now operational and regulating flow over the Ontario-Michigan interconnections. The operation of these PARs helps control inter-jurisdictional loop flows and assists in the management of system congestion.

The transmission lines east of Mississagi TS and the north-south corridor have experienced increased congestion due to the continuing addition of new renewable resources and reduced demand. It is expected that congestion will further increase with projects in the area, both proposed and under construction becoming operational. To help incorporate the future Lower Mattagami expansion projects and other renewable generation resources and to reduce likelihood of congestion, Hydro One installed series compensation on the 500 kV north-south lines at Nobel SS and dynamic reactive compensation facilities at Porcupine TS. To further improve the north-south transfer capability, Hydro One will install static reactive compensation facilities at Porcupine TS, Pinard TS, and Hanmer TS and dynamic reactive compensation facilities at Kirkland Lake TS. All the static and dynamic compensation facilities are going in service gradually, with the last one scheduled for 2013.

The Government of Ontario's Long-Term Energy Plan (LTEP) specifies five priority transmission projects to accommodate renewable generation to serve new load and support reliability. Furthermore, in a Supply Mix Directive on February 17, 2011, the OPA was required to include the five priority projects as part of long-term planning:

- Devices to enhance transfer capability, such as series or static var compensation, or other similar devices, in southwestern Ontario
- Enhance the East-West Tie along the east shore of Lake Superior through a new line
- Upgrade existing lines west of London
- A new line west of London
- New line to Pickle Lake

Northwestern Ontario (northwest) is connected to the rest of the province by the double circuit 230 kV East-West Tie. The Region has significant amounts of hydro-electric generation as well as other resources such as coal, gas, and biomass. As part of the coal shutdown, Atikokan and Thunder Bay (totaling 500 MW of generation capacity) will cease coal-fired operation by 2014. To maintain supply security in this area under the wide range of possible system and water conditions, additional resources located in the northwest or increased westbound transfer capability into this Region through the East-West Tie are required. The conversion of Atikokan to biomass and Thunder Bay to gas operation, as indicated in the LTEP, is part of the solution. The expansion of the East-West Tie is to provide a long-term reliable and cost-effective supply to the northwest. The line is anticipated to be in service no sooner than 2017.

A new supply line to Pickle Lake is currently being planned as part of a potential suite of options that may be required to serve growing load and maintain reliability in the system north of Dryden. Load in and north of this area is forecast to grow substantially over the next 10 to 15 years, and it is expected that new supply to the area will be required around 2015. Various options, both 230 kV and 115 kV are being studied, with lengths up to 300 km. These options will have some capability to support growth in the Red Lake Area to provide operational flexibility to enable refurbishment of end-of-life equipment, and to serve new load for mining operations in the area known as the Ring of Fire. The Ring of Fire Area is approximately 350 km northeast of Pickle Lake. If the new supply line to Pickle Lake is delayed, load that is being planned for connection after 2015 will not be able to connect until the new line is available. Studies have identified the need for incremental reactive capability throughout the region north of Dryden to support load growth, and there may also be the need for reactive devices at strategic locations in the bulk system at and west of Mackenzie TS.

The LTEP includes three transmission projects to accommodate additional renewable generation in southwestern Ontario: two upgrade projects and one new transmission line project. The two upgrade projects consist of a reactive compensation project and a line re-conductoring project. For the reactive compensation project, the OPA has recommended installation of an SVC with a capacitive capacity of 350 Mvar and connecting to the 500kV voltage level at the Milton Station. An in-service date of spring 2015 has been established for this project. The planned line re-conductoring project will consist of re-conductoring approximately 70 km of 230 kV transmission line between Lambton TS and Longwood TS. The two upgrade projects are intended to maximize the capability of the existing system and increase capability to incorporate additional renewable resources in a shorter time frame than a new transmission line can be built. A new transmission line west of London is targeted to be completed in 2017.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering Nuclear Generating System. Pickering Nuclear Generating System units connect directly to the 230 kV system at Cherrywood TS, east of the Greater Toronto Area. The retirement of Pickering Nuclear Generating Station would require an additional 230 kV supply source for the Pickering and Oshawa Areas. Plans are currently being developed for construction of the Clarington 500/230 kV Transformer Station by as early as 2015.

As demand increases in the western part of the Greater Toronto Area, the loading on the 500/230 kV transformers at Claireville TS and Trafalgar TS will exceed their capacity by about the middle of this decade. An additional 500 to 230 kV supply source would be required to relieve the loading on the existing autotransformers. Installation of 500/230 kV transformers later in this decade at the 500 kV Milton Switching Station is one of the options under consideration.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters in Ontario together with the OPA proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions. Delays to the in-service dates of bulk transmission projects resulting from delays in obtaining required approvals or delays in construction may result in increased congestion or Special Protection Systems (post-contingency generation rejection) in the interim.

System reinforcements are also being considered in a number of regional areas throughout the province, such as Kitchener-Waterloo-Cambridge-Guelph, York Region, and Ottawa, in order to maintain a reliable local supply of electricity. The OPA's regional planning approach addresses project delays. Regional planning develops options for each need, in a coordinated manner, guided by principles that maintain a long-term view that anticipates uncertainties and maintains flexibility. Conservation, supply, and transmission plans are coordinated to deliver the solutions that are required for each locale.

Québec

The Québec Area is projecting adequate Planning Reserve Margins throughout the long-term assessment period, varying between 12.1 and 15 percent. For the first year considered in this assessment, the 2013/2014 winter peak, the Anticipated Reserve Margin is 12.36 percent, which is above the NERC Reference Reserve Margin of 10 percent. Québec's Anticipated Reserve Margin for the 2012/2013 winter is projected to be 10.8 percent, also above the NERC Reference Margin Level 9.6 percent.[34] The NERC Reference Reserve Margin Levels are drawn from the most recent Québec Balancing Authority Area Comprehensive Review of Resource Adequacy.

The Planning Reserve Margins projected in this assessment are adequate and result mostly from the commissioning of additional resources, most of which are new hydro projects, such as La Sarcelle Generating Station, the Romaine River Complex (Romaine 1, 2, 3, and 4), additional capacity at Sainte-Margerite-3 Generating Station, and wind and biomass resources. Moreover, an additional amount of Demand Response programs contributes to this adequate level of projected reserve margins.

In this assessment, the Gentilly-2 nuclear station will be out of service for decommissioning at the end of 2012. The Tracy and La Citière thermal generating stations have also been permanently retired.

[34] Additional information on the 2012/2013 winter season can be found in the NERC *Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

Demand

The compound annual growth rate (CAGR) forecast for Total Internal Demand is 0.79 percent during the next 10 years (2013/2014 – 2022/2023 winter seasons), which is slightly lower than the one percent growth rate forecast reported in the 2011 LTRA. As for the Net Energy for Load (NEL), the average growth rate forecast is also 0.8 percent, compared to a 0.6 percent growth rate forecasted last year. The Net Internal Demand for the 2013/2014 winter peak is projected to be 37,810 MW, which is 267 MW higher than the forecasted 2012/2013 winter peak demand. The demand forecast methods used in this assessment have not changed from previous years

Hydro-Québec's demand and energy-sales forecasting is Hydro-Québec Distribution's responsibility. First, the energy-sales forecast is built on the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sectors sales. The sum of these monthly end-use/sector peak demands is the total monthly peak demand.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 36-year of temperatures (1971-2006) adjusted for a global warming annual effect of 0.30 °C (0.54 °F) per decade starting in 1971. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of those 252 scenarios. Load uncertainty is due to the uncertainty of economic and demographic variables that affect demand forecast and the residual errors from the models. The Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty.

Demand Side Management

The only Demand Response programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are interruptible demand programs (for large industrial customers) totaling 1,660 MW for the 2013/2014 winter period, decreasing to 1,300 MW by the final year of the assessment (Table 15). It is usually used in situations when load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. Demand Response is relatively stable over the assessment period, with a maximum reached for the 2013/2014 winter peak period.

Table 15
Québec Projected Demand-Side Management

	Short-Term		
NPCC-Québec-Winter	2013/14	2014/15	2015/16
Direct Control Load Management (DCLM)	250	250	250
Contractually Interruptible (Curtailable)	1,660	1,439	1,439
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	0	0	0
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,910	1,689	1,689
TOTAL ENERGY EFFICIENCY	1,980	2,150	2,300
TOTAL DEMAND-SIDE MANAGEMENT	**3,890**	**3,839**	**3,989**

Total Energy Efficiency/Conservation is included in the forecast load and accounts for 1,980 MW at the 2013/2014 winter peak period. Energy Efficiency is growing throughout the entire period of the assessment. The total on-peak Demand Response and Energy Efficiency/Conservation for the 2022/2023 winter period is projected to be approximately 4,740 MW.

On a yearly basis, Hydro-Québec Distribution presents its Energy Efficiency Plan Update, “Plan global en efficacité énergétique,” to the Québec Energy Board for the next and upcoming years. This plan focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. Examples of programs and tools for promoting energy savings for the residential customers include old refrigerator recycling, electronic thermostats, low-energy lighting, etc. The provincial government, through its Ministry of Natural Resources, also implements Energy Efficiency/Conservation programs, mainly in the area of building standards and housing insulation.

Generation

At the time of this assessment, available resources for the next winter in the Québec Area are evaluated at 39,502 MW, most of which are hydropower generation (97 percent). Wind and biomass resources, which are owned and operated by Independent Power Producers (IPPs) and under long-term power purchase agreements with Hydro-Québec Distribution and Hydro-Québec Production, account for two percent of the available capacity. Hydro-Québec Production also operates one fuel oil generating station (for peaking purposes), which represents about one percent of the total available capacity (Table 16).

Table 16
Québec Current Capacity[35]

NPCC-Québec-Winter	Current Capacity	Current Share
Coal	0	0.0%
Petroleum	436	1.1%
Gas	0	0.0%
Nuclear	0	0.0%
Other/Unknown	0	0.0%
Renewables	39,066	98.9%
TOTAL	**39,502**	**100.0%**

The Existing-Certain capacity increased by an amount of 1,240 MW since the previous assessment, of which 720 MW are from hydropower generation and 520 MW from wind and biomass.

TransCanada Energy's 547MW natural gas combined-cycle generating station in Bécancour is mothballed and accounts for the total Existing-Inoperable resources. Each summer, Hydro-Québec Distribution must decide whether to mothball the Bécancour power plant for an additional year or to re-start it for the coming year. Although this plant is expected to be mothballed until December 2017, it could be re-started sooner if needed.

As mentioned above, the Gentilly 2 nuclear station (675 MW) will be out of service for decommissioning at the end of 2012. Two thermal generating stations have also been permanently retired since the last assessment—Tracy (450 MW) and La Citière (280 MW). In the previous assessment, the Tracy power plant was mothballed over the entire assessment period.

The temporary unit shutdown and retirements described above are offset by the commissioning of new resources. The last two units of La Sarcelle Hydro Generating Station (50 MW each) are to be commissioned during the 2012/2013 winter period. The Romaine-2 (622 MW) and Romaine-1 (260 MW) Hydro Generating Station are under construction and are expected to be commissioned for the 2014/2015 and 2016/2017 winter peak periods respectively. The added capacity at Sainte-Margerite-3 is expected to be commissioned for the 2017/2018 winter peak period, adding 440 MW of capacity. Two other generating stations at the Romaine Complex (Romaine-3 and Romaine-4) are expected to be commissioned later during the assessment period (2017/2018 and 2020/2021), adding 668 MW of capacity to the system

- In recent years, Hydro-Québec Distribution has launched several calls for tenders and electricity purchase programs for new renewable supplies, which will also be commissioned in the next years:
- 2,290 MW of wind power to be commissioned between 2012 and 2015.

[35] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

- 125 MW generated by small hydro plants (50 MW and less) developed in partnership with local and First Nations communities, will be commissioned between 2012 and 2014.
- 300 MW generated from biomass to be commissioned between 2012 and 2016.

As for behind-the-meter generation, it is negligible and is included in the load forecast. For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, maximum capacity and expected on-peak capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, which represents 490 MW and 973 MW respectively for the 2012/2013 (current) and 2022/2023 winter periods. The maximum wind capacity is equal to contractual capacity, which generally equals to its nameplate capacity. For summer peak periods, the expected on-peak wind capacity is set to zero as wind resources are completely derated (Table 17).

Table 17
Québec Renewable Capacity [36]

	Current	
NPCC-Québec-Winter	Capacity	Share
Hydro	38,315	98.1%
Pumped Storage	0	0.0%
Geothermal	0	0.0%
Wind	490	1.3%
Biomass	261	0.7%
Solar	0	0.0%
TOTAL	**39,066**	**100.0%**

Wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up, and the following are under study:

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability; efficiency losses in generating units also expected.
- Reduction of low-load operation flexibility due to low inertial response of wind generation coupled to must-run hydroelectric generation.

[36] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Capacity Transactions

Expected capacity purchases are planned by Hydro-Québec Distribution as needed for the Québec internal demand. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections' transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

The Québec Area will support firm capacity sales totaling 398 MW to New England and Ontario (Cornwall) during the 2013/2014 winter peak, backed by Firm contracts for both generation and transmission, but which will decline to 145 MW in 2020 (Table 18). Moreover, 228 MW of Firm exports for the 2014/2015 winter period and 500 MW for the 2015/2016 winter peak are committed for neighboring area's needs.

Table 18
Québec Projected Capacity Transactions

NPCC-Québec-Winter	2013/14	2014/15	2015/16	2016/17	2017/18
Expected Imports	1,100	1,100	1,100	1,100	1,100
Firm Imports	0	0	0	0	0
TOTAL IMPORTS	1,100	1,100	1,100	1,100	1,100
Expected Exports	0	0	0	0	0
Firm Exports	398	626	676	151	151
TOTAL EXPORTS	398	626	676	151	151
TOTAL NET CAPACITY TRANSACTIONS	**702**	**474**	**424**	**949**	**949**

The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level.

Transmission

This section briefly describes the BPS transmission additions anticipated to be in service during the assessment period. Descriptions for each project of particular importance are also included below

The Romaine River Hydro Complex Integration

Construction of the first phase of transmission infrastructures for the Romaine River Hydro Complex project has now begun. The generating stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 and Romaine-1 will be integrated in 2014/2016 at Arnaud 735/315 kV substation. Romaine-3 and Romaine-4 will be integrated in 2017/2020 at Montagnais 735/315 kV substation.

Main system upgrades for this project require construction for 2014 of a new 735 kV switching station to be named "Aux Outardes," located between the existing Micoua and Manicouagan Transformer Stations. Two 735 kV lines will be redirected into the new station and one new 735 kV line (3 miles) will be built between Aux Outardes and Micoua.

The Bout-de-l'Île 735-kV Section

Hydro-Québec TransÉnergie is adding a new 735 kV section at Bout-de-l'Île (east end of Montréal Island) substation. This was originally a 315/120 kV station. The Boucherville–Duvernay 735 kV line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300 Mvar Static Var Compensator will be integrated into the 735-kV section in 2013.

The project also includes the addition of two 735/315 kV, 1,650 MVA transformers in 2014. This new 735 kV source will allow redistribution of load around the Greater Montréal Area and will absorb load growth in the eastern part of Montréal. This project will enable future major modifications to the Montréal Area regional subsystem. Many of the present 120 kV distribution stations will be rebuilt into 315 kV stations, and the Montréal regional network will be converted to 315 kV.

The Northern Pass Project

This project to increase interconnection transfer capability between Québec and New England by 1,200 MW is now being studied. The project involves construction of a ±300 kV dc transmission line about 46 miles long from Des Cantons 735/230 kV substation to the Canadian-U.S. border. This line will be extended into the United States to a substation built in Franklin, New Hampshire.

The project in Québec also includes the construction of two 600 MW converters at Des Cantons and a 300 kV dc switchyard. Permitting for this project is presently ongoing but the initial commissioning date of 2015 may be delayed.

Wind Generation Integration Projects

A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages in order to integrate wind generation planned to come on-line in the next few years. These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

Projects on the main system include 735 kV series compensation additions, and the addition of a second SVC at Bout-de-l'Île substation after the addition of the previously mentioned 735 kV section, and an SVC at Jacques-Cartier substation. Nominal current upgrades will also be done on some existing series compensation, and a thermal capacity upgrade will be done on two 735 kV lines. However, the future construction of the Chamouchouane–Bout-de-l'Île 735 kV line (see below) will replace a number of the above-mentioned projects.

Chamouchouane – Bout-de-l'Île 735 kV Line

The large generation additions and transmission services coming up over the next years require, as shown above, a number of system additions to maintain reliability. Moreover, planning studies have shown that to optimize the different solutions and to significantly reduce marginal losses on the system due to this new generation, a new 735 kV line from Chamouchouane substation on the eastern James Bay subsystem to Bout-de-l'Île substation in Montréal (about 230 miles) is required. Planning, permitting and construction delays are such that the line is scheduled for the 2017/2018 winter peak period. This optimization will result in replacing some of the above-mentioned projects, and in other cases will result in reducing additional equipment that was previously planned. The new line will also reduce transfers on other parallel lines on the Manicouagan–Québec 735 kV interface, thus optimizing operation flexibility and reducing losses.

Public information meetings have begun on this project. Final line route has not been determined yet and government authorization processes are ongoing.

- **Regional Projects Under Construction**
- There are a number of regional projects now underway. The three most important are listed here:
- Limoilou 230/25 kV substation in Québec City; in service fall 2012;
- St-Bruno 315/25 kV substation south of Montréal; in service fall 2013; and,
- Bécancour 230 and 120 kV system reinforcement; Bécancour Industrial Park, in service fall 2012.

Upcoming Regional Projects

Other regional substation and/or line projects are now in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City Areas and another dozen in other areas within service dates from 2012 to 2018.

Planning studies leading to system enhancement projects such as those mentioned above ensure that there will be no long-term transmission constraints in the Assessment Area. Generation on the system is integrated on a 100 percent Firm basis. Moreover, there are no project delays or temporary service outages for any transmission facilities (lines or transformers) that will impact long-term reliability during the assessment period.

The Hydro-Québec system has sufficient transmission being constructed to support all Future-Planned generation forecast to come on-line during the assessment period.

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 19 and Figure 8.

Table 19
PJM, RFC-Other and MRO-US 2013 Assumptions [37]

	PJM	RFC-Other	MRO-US
Peak Load (MW)	161,240	42,428	30,923
Peak Month	July	July	July
Assumed Capacity (MW)	183,856	48,711	35,318
Purchase/Sale (MW)	-802	0	0
Reserve (%)	14	15	14
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	10,278	3,568	2,600
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	1,100	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	200	200
Load Forecast Uncertainty	94.66% +/- 5.57%, 11.13%, 16.7%	94.44% +/- 4.78%, 9.57%, 14.36%	94.44% +/- 4.78%, 9.57%, 14.36%

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 2008 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.

Unit data was from the publicly available NERC data. Each individual unit represented in the non-PJM RFC region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

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

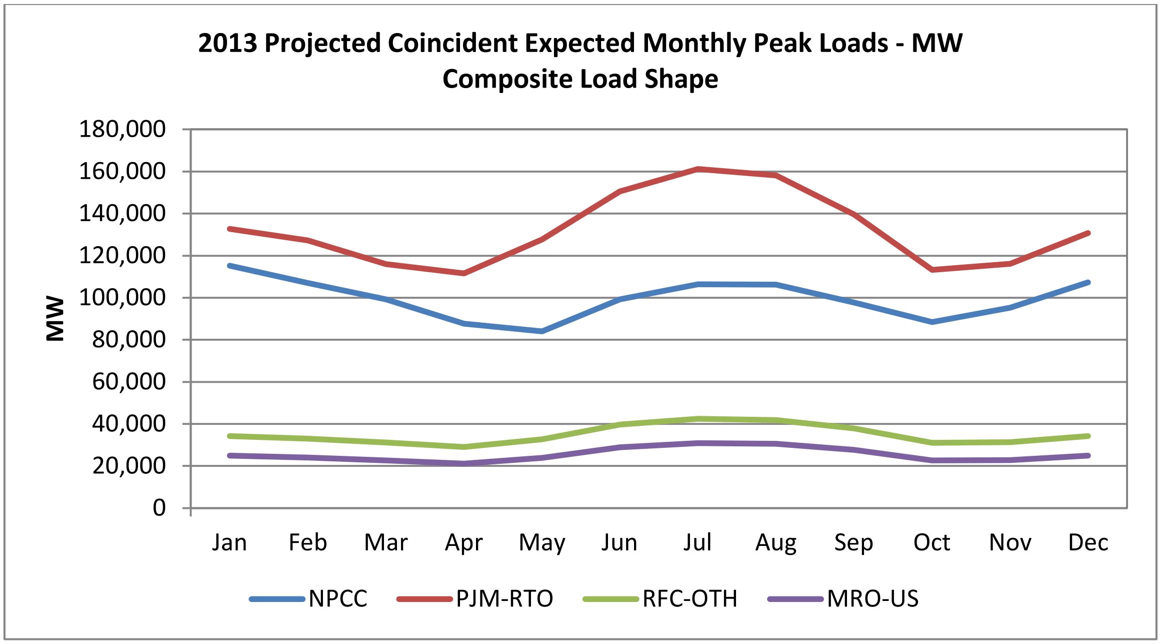

Figure 8 - 2013Projected Monthly Expected Peak Loads for NPCC, RFC, PJM and the MRO

Reliability*First*

Reliability*First* is a 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*.

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. Each individual unit represented in the MRO-US region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

PJM-RTO

Load Model

The forecast contained in the January 2012 PJM Load Forecast [38] was used, consistent with the 2012 RRS. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis) and Manual 20 (PJM Resource Adequacy Analysis.) [39] 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, January 2012, for the forecast monthly loads. This study modeled load forecast 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 is forecast.

Modeling

The modeling of PJM-RTO breaks the PJM region into four distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, 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 2012 reserve requirement study.

Demand

Summer peak load growth for the PJM RTO is projected to average 1.36 percent per year over the next 10 years. The PJM RTO summer peak is forecast to be 176,420 MW in

[38] See: http://www.pjm.com/~/media/documents/reports/2011-pjm-load-report.ashx

[39] Please refer to PJM Manual 19 http://pjm.com/~/media/documents/manuals/m19.ashx and PJM Manual 20, http://ftp.pjm.com/~/media/documents/manuals/m20.ashx for technical specifics.

2022, a 10-year increase of 20,166 MW. Annualized 10-year growth rates for individual PJM transmission zones range from 0.9 percent to 1.9 percent.

A downward revision to the near-term economic outlook for both the United States and PJM Area resulted in lower peak and energy forecasts in the 2012 load forecast compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the recovery of the U.S. economy. While growth in later years accelerates, the historic growth rate will not be restored until past the assessment period.

This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment). A summary report of economic assumptions used in the 2012 load forecast provided by Moody's Analytics states that:

> *Mid-Atlantic and Virginia Areas are expected to be among the fastest growing in the PJM service territory. Long-term growth in these metro areas will be driven by highly educated labor forces, favorable demographics, productivity growth, and for some Virginia metro areas, plentiful and affordable housing, and relatively low costs. Metro areas in Ohio and Pennsylvania are expected to grow more slowly. Expansion in those states will be more restrained as regions transition away from manufacturing toward more services-oriented economies.*

No footprint changes are included in these calculations. East Kentucky Power Cooperative (EKPC) has announced its intention to join PJM on June 1, 2013. EKPC is a not-for-profit, member-owned cooperative providing wholesale electricity to 16 owner-member distribution cooperatives that serve 520,000 homes, farms, and businesses across 87 of the 120 counties in Kentucky. EKPC owns and operates four major power plants with a total generating capacity of about 3,000 megawatts, as well as approximately 2,800 miles of high-voltage transmission line. Peak load was 2,889 MW.

Demand-Side Management

Last year PJM had 11,600 MW of Demand-Side resources available during the summer peak period. PJM expects similar amounts for this year's summer peak period. Because PJM has a shorter history with accepting Demand Response and Energy Efficiency, the forecasts are conservative. Accordingly, Demand Response will remain slightly below was available during the 2011 peak. The Energy Efficiency will increase from 728 MW in 2013 to 804 MW in 2022 (Table 20).

Table 20
PJM Projected Demand-Side Management

	Short-Term		
PJM-Summer	2013	2014	2015
Direct Control Load Management (DCLM)	1,000	1,000	1,000
Contractually Interruptible (Curtailable)	5,000	7,200	7,200
Critical Peak-Pricing (CPP) with Control	0	0	0
Load as a Capacity Resource	5,000	5,000	5,000
TOTAL LOAD-MODIFYING DEMAND RESPONSE	11,000	13,200	13,200
TOTAL ENERGY EFFICIENCY	728	804	804
TOTAL DEMAND-SIDE MANAGEMENT	**11,728**	**14,004**	**14,004**

Demand-Side resources accepted through the Forward Capacity Market are DSM that is dispatched like generator resources and is treated as such. The more typical type of Demand-Side resource is the kind that is retained for use by the PJM operators during capacity emergencies, and it reduces load.

Energy Efficiency programs are included in the 2013–2022 load forecasts with approval for use in the PJM Reliability Pricing Model (RPM). Energy Efficiency is included as a capacity resource in the RPM Market but is limited to a maximum of four years. The Energy Efficiency then becomes part of the load forecast. Measurement and verification of Energy Efficiency programs are governed by rules specified in PJM Manual 18B.[40] To demonstrate the value of an Energy Efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing Measurement and Verification (M&V) plans, providing post-installation M&V reports, and undergoing an M&V audit.

There are some minor concerns related to the amount of information available to PJM, which can be used to determine the amount of DR to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have a reliability concern, but the additional information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions. PJM has addressed the issue of availability by creating three different DR products: Limited DR (10 days for six hours per day), Extended Summer DR (unlimited days during summers for 10 hours per day) and Annual DR (unlimited days for 10 hours per day), and requiring the necessary amount of annual capacity (DR or generation) to fulfill the PJM reliability requirements. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

Generation

The predominant source of fuel in PJM is coal at approximately 42 percent. Next is natural gas at 26 percent and nuclear at 18 percent (Tables 21 and 22). Since the 2011 assessment, along with the DOEK generation, PJM added 1,608 MW of natural gas generation, 117 MW of existing nuclear generation uprates are included, and 280 MW of nameplate wind generation with 42 MW counted as Existing-Certain.

In addition, 70 MW of nameplate solar generation with 27 MW counted as Existing-Certain. No capacity resource changes are expected though the summer of 2012.

[40] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

Table 21
PJM Current Capacity [41]

PJM-Summer	Current Capacity	Current Share
Coal	78,105	42.1%
Petroleum	11,739	6.3%
Gas	52,395	28.3%
Nuclear	33,666	18.2%
Other/Unknown	0	0.0%
Renewables	9,519	5.1%
TOTAL	**185,424**	**100.0%**

Table 22
PJM Current Renewable Capacity[42]

PJM-Summer	Current Capacity	Current Share
Hydro	2,677	28.1%
Pumped Storage	5,145	54.0%
Geothermal	0	0.0%
Wind	711	7.5%
Biomass	943	9.9%
Solar	42	0.4%
TOTAL	**9,519**	**100.0%**

PJM had a total increase of 5,007 MW since last summer almost completely due to the addition of DEOK generation. Generation additions and retirements in the rest of PJM almost netted out. A new natural gas combined-cycle unit at Dresden was added at 545 MW. Kearny natural gas units 13 and 14 were added for 267 MW. A new natural gas combined-cycle unit named Virginia City was added in AEP for 585 MW.

Martins Creek 4 oil unit was uprated 70 MW in PPL. Susquehanna nuclear units 1 and 2 in PPL were uprated 45 MW each. A net of 568 MW of uprates and derates also occurred.

Benning 15 and 16, totaling 548 MW of oil generation, were retired in the Baltimore Gas and Electric (BGE) footprint. Gorsuch units 1–4, totaling 189 MW of coal generation, were retired in AEP. The Buzzard Point East and West oil CTs totaling 210 MW were retired in Pepco. The Hudson 1 natural gas unit at 322 MW was retired in PSE&G. Also in PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW. The State Line 3 and 4 units were retired from ComEd, totaling 515 MW.

No units were brought back into service since the last assessment. PJM has no on-going long-term outages of generation. There are no significant project deferrals or cancellations; occasional delays are expected but should not cause any reliability problems. Behind-the-meter generation is not considered as capacity in PJM. It offsets load that is also behind the meter.

[41] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[42] *Ibid*.

The Laurel Mountain Energy Storage Facility consists of eight Smart Grid Stabilization System Lithium Ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm located at Laurel Mountain, West Virginia. A two MW (300 kilowatt hours of storage) battery for frequency regulation has been installed on the same property as the Paradise Solar project in Deptford, New Jersey.

PJM uses the maximum generator capability expected capacity on-peak (Existing-Certain). This capability may only be available for a limited period of time, but PJM requires that units be able to produce this amount over the peak hours. PJM requires annual verification of this capability. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked, and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor. No enhancements have been made as to how expected on-peak capacity values are calculated for each resource in PJM. PJM does not anticipate any reliability concerns resulting from minimum demand and over generation. Intermittent resources can be required to disconnect. Established procedures address reliability concerns caused by over-generation.

Capacity Transactions

All transactions are Firm for both specific generation and transmission (Table 23). Firm contacts are mostly long-term, but some are shorter in the one- to three-year time frames. All transactions are assumed to continue through the entire assessment period unless a termination date has been specified. While it is possible that the termination dates could be extended, experience shows that the transaction usually ends on the date contracted. PJM has no reliance on outside assistance for emergency imports. There is no emergency generation needed to be available to meet PJM Reserve Margin Requirement.

Table 23
PJM Projected Capacity Transactions

PJM-Summer	2013	2014	2015	2016	2017
Expected Imports	0	0	0	0	0
Firm Imports	1,453	1,453	1,453	1,453	1,453
TOTAL IMPORTS	1,453	1,453	1,453	1,453	1,453
Expected Exports	0	0	0	0	0
Firm Exports	1,236	1,236	1,236	1,236	1,236
TOTAL EXPORTS	1,236	1,236	1,236	1,236	1,236
TOTAL NET CAPACITY TRANSACTIONS	**217**	**217**	**217**	**217**	**217**

Transmission

Today, as part of its ongoing RTO responsibilities, PJM's Regional Transmission Expansion Plan (RTEP) protocol comprises a process that considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant retirements, broader generation development patterns—including the evolution of renewable resources—as well as Demand-Side response (DSR) programs and Energy Efficiency (EE) programs.

This process culminates in one recommended plan (one RTEP) for the entire PJM footprint that is submitted to PJM's independent Board of Managers (PJM Board) for consideration and approval. Under contractual agreement, the PJM Board's approval then obligates transmission-owning utilities in PJM to build the facilities specified in the RTEP. This includes construction of new transmission lines and other facilities as well as upgrades to existing transmission assets.

The RTO Perspective

PJM operates and plans the transmission system region-wide, as a whole, ignoring corporate and state boundaries when taking operational action or making planning decisions. By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's RTEP process helps focus on transmission upgrades that meet Reliability Criteria and increase economic efficiency more effectively. PJM's existing RTEP Protocol[43] has been applied by PJM so as to evaluate reliability and market efficiency driving transmission expansion plans today using bright line triggers.

Baseline Reliability Upgrades

PJM's baseline reliability assessments identify areas where the electric power system, forecast over a specific time, would not be in compliance with NERC Reliability Standards. These baseline assessments lead to recommendations for enhancement plans, referred to as baseline transmission network upgrades, to ensure compliance with those standards. Fundamentally, the construction of baseline transmission upgrades is required to ensure that the PJM system remains in compliance with NERC Reliability Standards. This baseline then serves as the basis for the analysis of subsequent requests for transmission service and interconnection.

Scope of Upgrades Discussed

In 2011 alone, the PJM Board approved approximately 400 individual Bulk Electric System (BES) upgrades. However, to put reasonable parameters around the scope and length of this report, the upgrades discussed here are generally those whose costs exceed $5 million. A complete list of all approved RTEP upgrades, a brief description of facility and driver, and current status can be found on PJM's website.[44]**.**

TrAIL

The 500 kV Trans Allegheny Interstate Line (TrAIL) was placed in service on May 23, 2011, improving reliability into such congested areas as Washington, D.C., Baltimore, and northern Virginia. The TrAIL line was built in three segments, connecting

[43] As codified in Schedule 6 of PJM's Operating Agreement (http://www.pjm.com/documents/~/media/documents/agreements/oa.ashx) and described in detail in the PJM manuals (http://www.pjm.com/documents/manuals.aspx).

[44] http://www.pjm.com/planning/ rtep-upgrades-status/construct-status.aspx.

substations in southwestern Pennsylvania, northern West Virginia and northern Virginia. Built by and jointly owned by Allegheny Energy (now FirstEnergy) and Dominion, the 220-mile TrAIL line was the first high-voltage backbone transmission line approved by the PJM Board through PJM's planning process to enter commercial operation.

MAPP Abeyance

The Mid-Atlantic Power Pathway (MAPP) was placed in abeyance by the PJM Board on August 18, 2011. PJM 2011 RTEP generator sensitivity analysis indicated that the need for the line has moved out several years, beyond 2015, but as early as 2019. The PJM Board has also directed PJM to perform additional sensitivity analyses as part of the 2012 RTEP cycle of analysis—including the impact of May 2012 RPM auction results—to assess the need to further address MAPP abeyance.

Susquehanna–Roseland

In 2007 the PJM Board approved the Susquehanna–Roseland 500 kV line to resolve numerous overloads on critical 230 kV circuits across eastern Pennsylvania and northern New Jersey beginning in 2012. PJM's 2008 RTEP Retool validated the required June 1, 2012 in-service date in light of 23 single contingency Reliability Criteria thermal violations and NERC Category C double-circuit tower line contingency thermal violations. PJM's 2009 RTEP Retool analysis for 2012 also included an assessment of the continued need for the Susquehanna–Roseland 500 kV line. Based on the identification of 13 single contingency thermal overloads and 10 double-circuit tower line outage overloads, PJM re-validated the line's June 1, 2012 in-service date.

PJM conducted additional analysis in 2011 to assess the impact of delays to the construction. Originally required to be in service by June 1 2012, regulatory delays have pushed the expected in-service date to June 1, 2015. Updated analysis using the 2011 load forecast confirmed double-circuit tower line (DCTL) violations beginning in summer 2012. The near-term solution is to operate to the DCTL violations in real-time operation and adjust generation and implement Demand-Side Response (DSR) as required to maintain grid reliability. Updated studies also show that Hudson Unit 1, previously designated as a reliability-must-run unit, is not required to maintain reliability and will be released.

PATH Abeyance

Analysis performed during the 2010 RTEP cycle required an in-service date of June 1, 2015 for the PATH Line. The PJM Board issued a statement on February 28, 2011, suspending the PATH line.

PJM staff performed an updated analysis based on the 2011 RTEP assumptions that included generation deliverability and load. Additional analysis performed on a 2017 study year case with 2011 RTEP assumptions examined the impact on the PATH abeyance from Warren Generation, Global Insights load forecast, RPS, at-risk generation and state DSR/EE goals. The 2011 RTEP analysis suggests that the need for the PATH line has moved several years beyond 2015. Based on these analyses the PJM Board decided to continue to hold the project in abeyance and requested that the Transmission

Owners suspend development activities. Furthermore, the PJM Board has directed staff to perform additional analysis using the 2012 RTEP assumptions and incorporating May RPM base residual auction results.

Static Var Compensators (SVC) to be Installed:

- Frost Bridge 138 kV; FirstEnergy (AP); 70 Mvar; 6/1/12
- Meadowbrook 500 kV; Primary Power; 600 Mvar; 6/1/14
- Mt. Storm 500 kV; Primary Power; 250 Mvar; 6/1/14
- Hunterstown 500 kV; FirstEnergy (ME); 500 Mvar; 6/1/14
- Altoona 230 kV; FirstEnergy (ME); 250 Mvar; 6/1/14

Fast Switching Capacitors

- Mansfield 345 kV; FirstEnergy (PN); 100 Mvar; 6/1/14
- Jack's Mountain 500 kV; FirstEnergy (PN); 100 Mvar; 6/1/17
- Jack's Mountain 500 kV; FirstEnergy (PN); 500 Mvar; 6/1/17

HVdc

- Bergen 230 kV (PSE&G-NJ)–49th Street 345 kV (ConEd–NY) 670 MW; 6/1/13

RESULTS

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2013-2017 period.

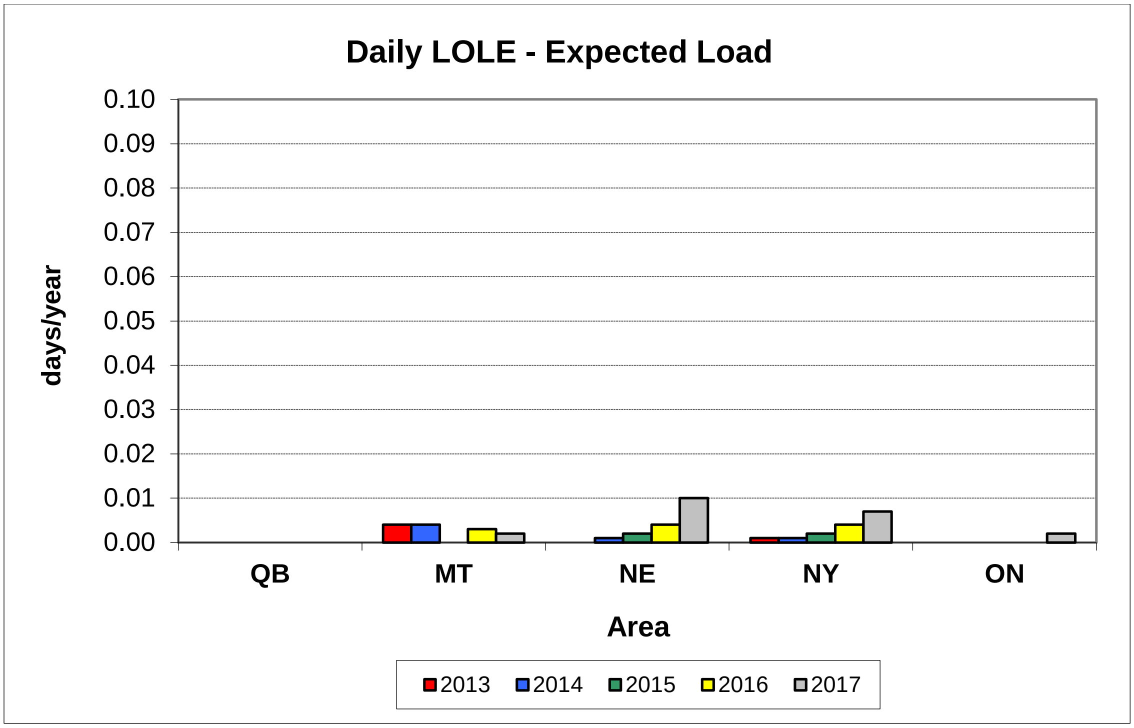

Figure 9(a) - Estimated Annual NPCC Area LOLE (2013 – 2017)

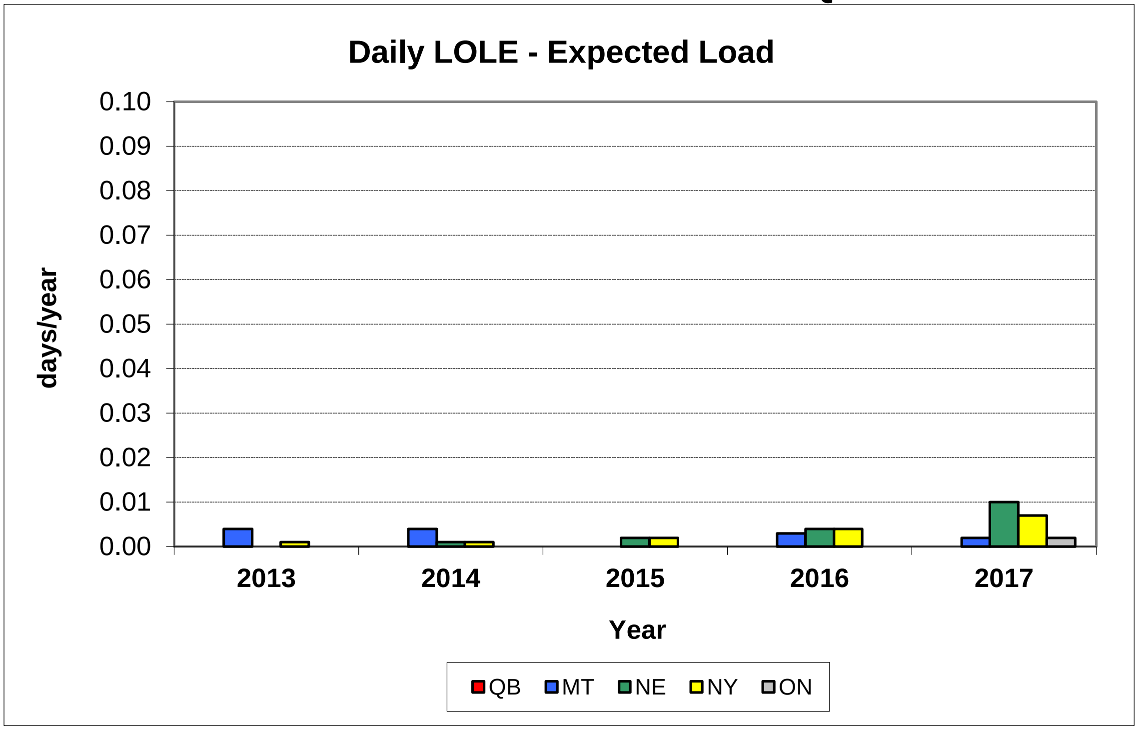

Figure 9(b) - Estimated Annual NPCC Area LOLE (2013– 2017)

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2013-2017 period.

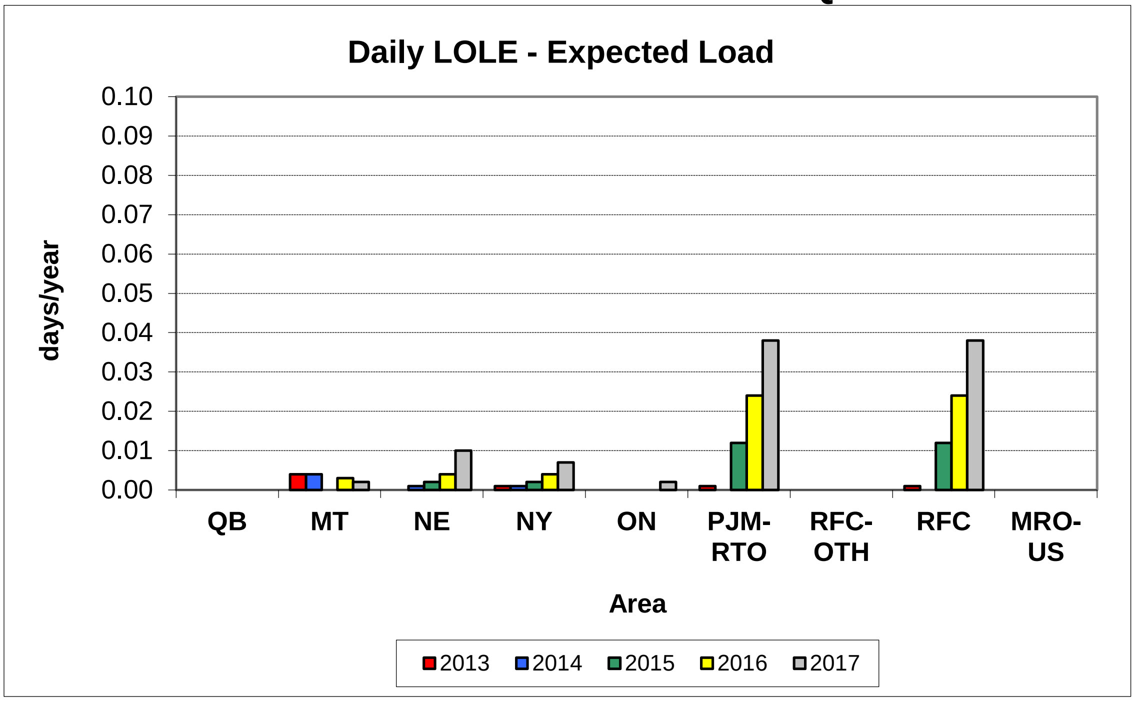

Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2013 – 2017)

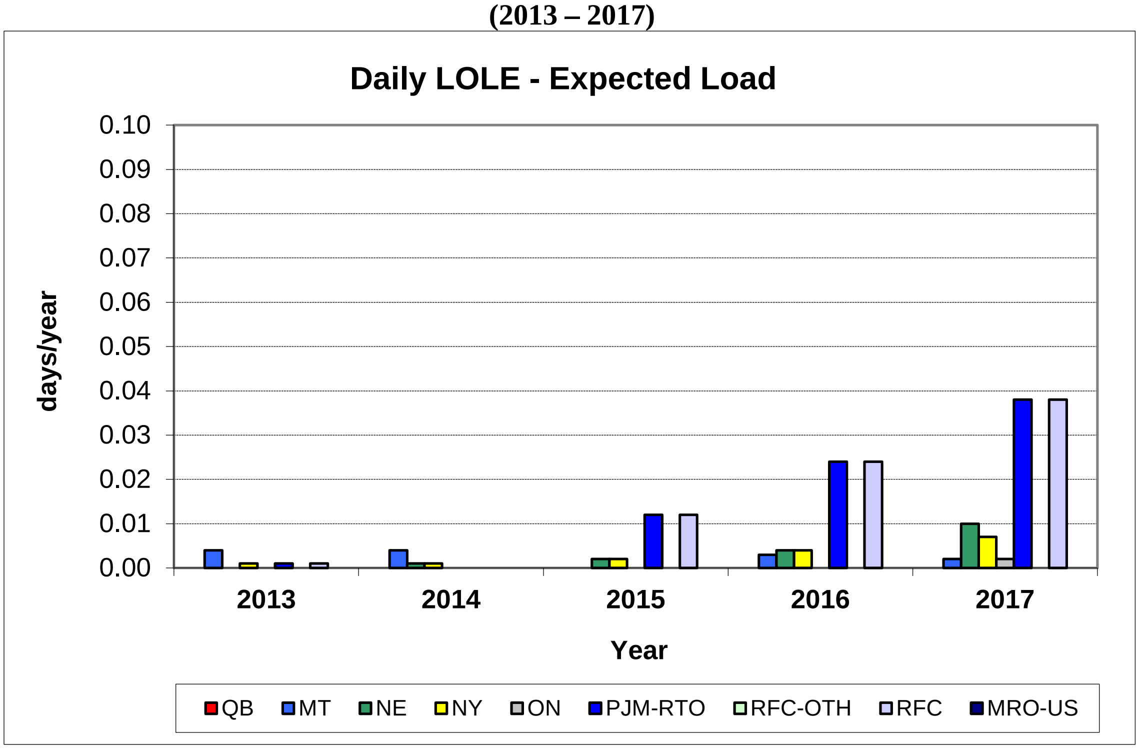

Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region's LOLE (2013 – 2017)

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2013-2017 period.

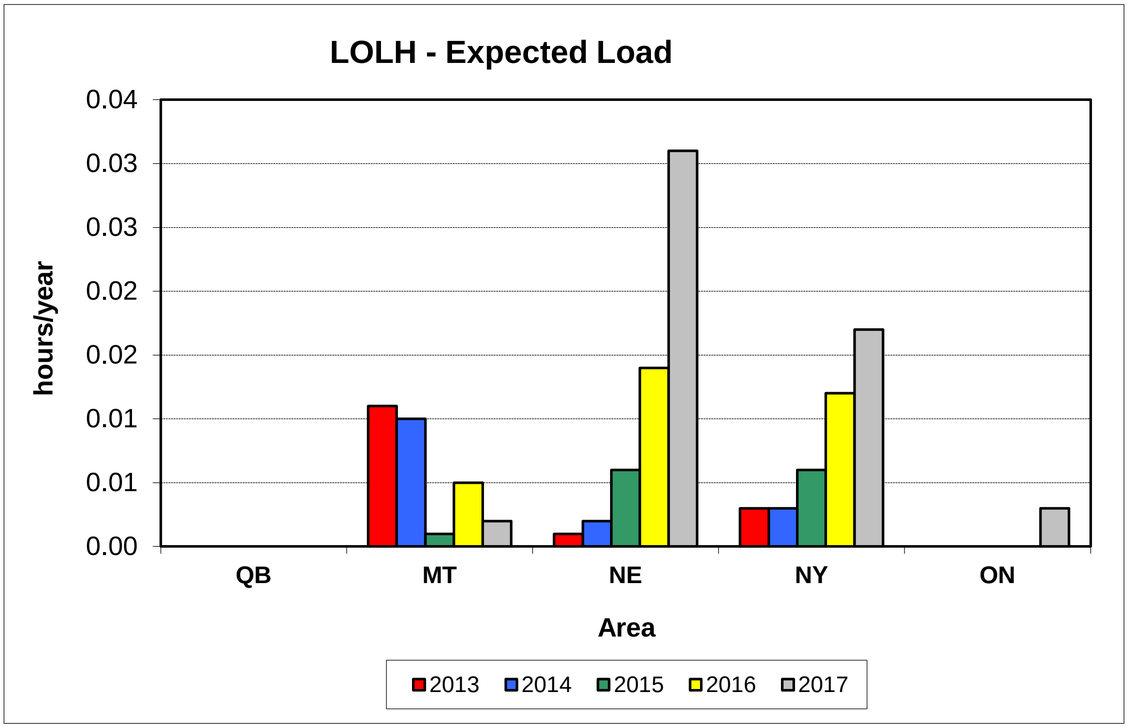

Figure 10(a) - Estimated Annual NPCC Area LOLH (2013 – 2017)

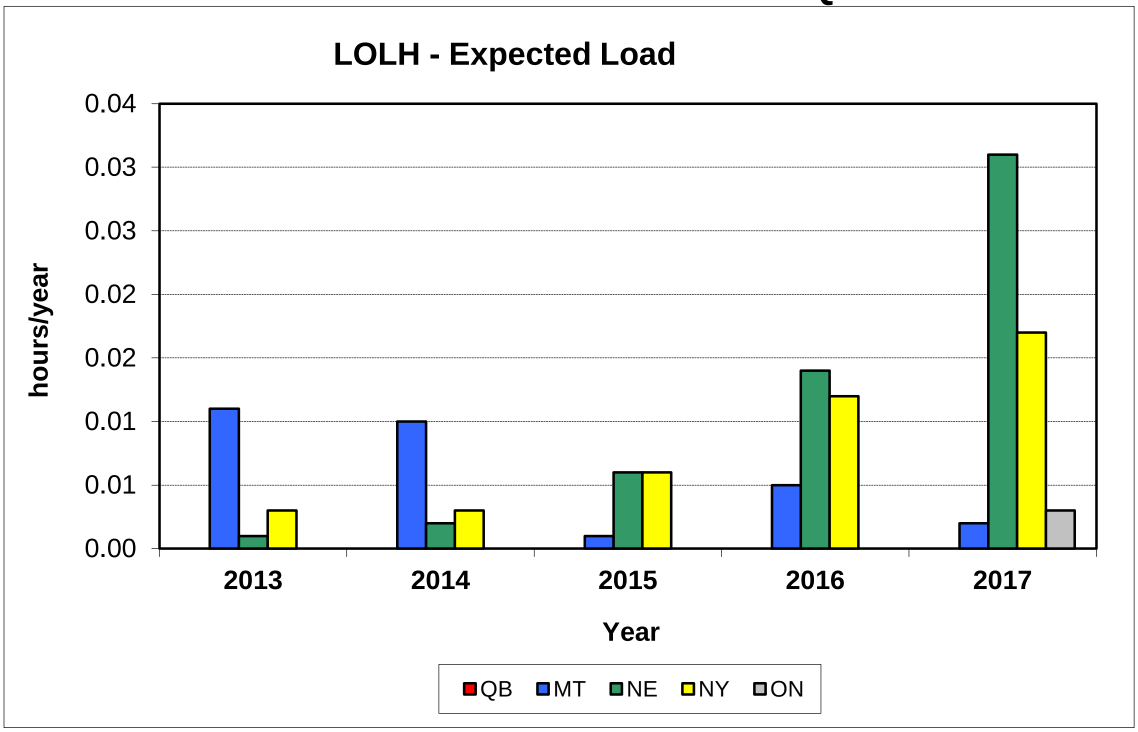

Figure 10(b) - Estimated Annual NPCC Area LOLH (2013 – 2017)

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2013-2017 period.

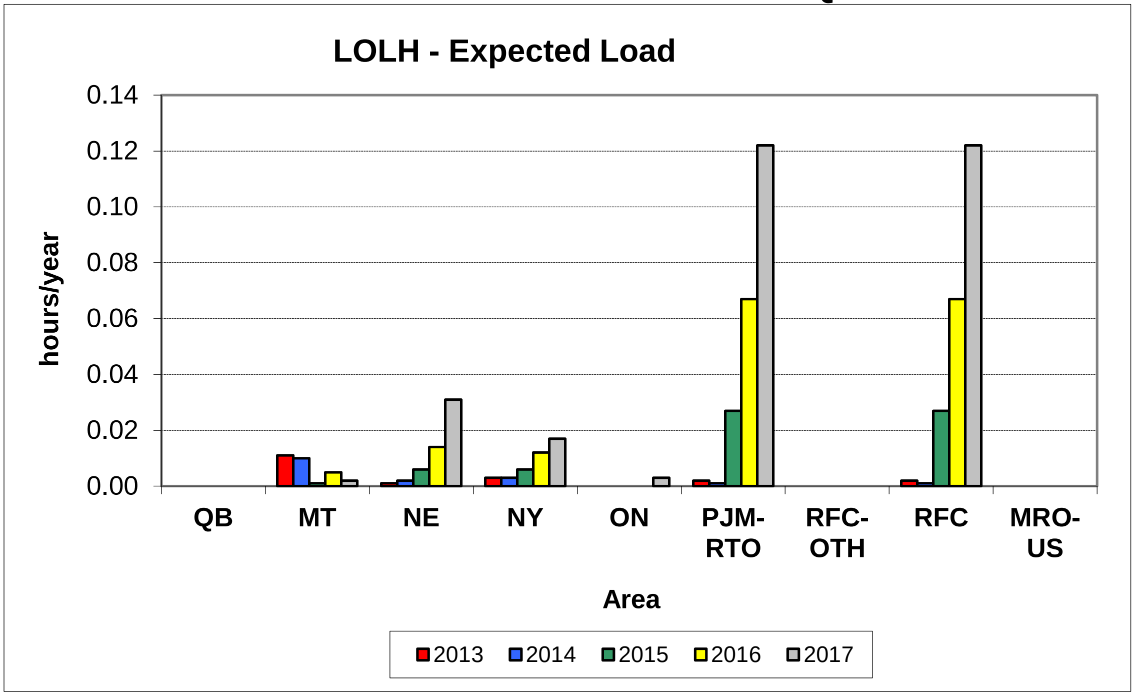

Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2013 – 2017)

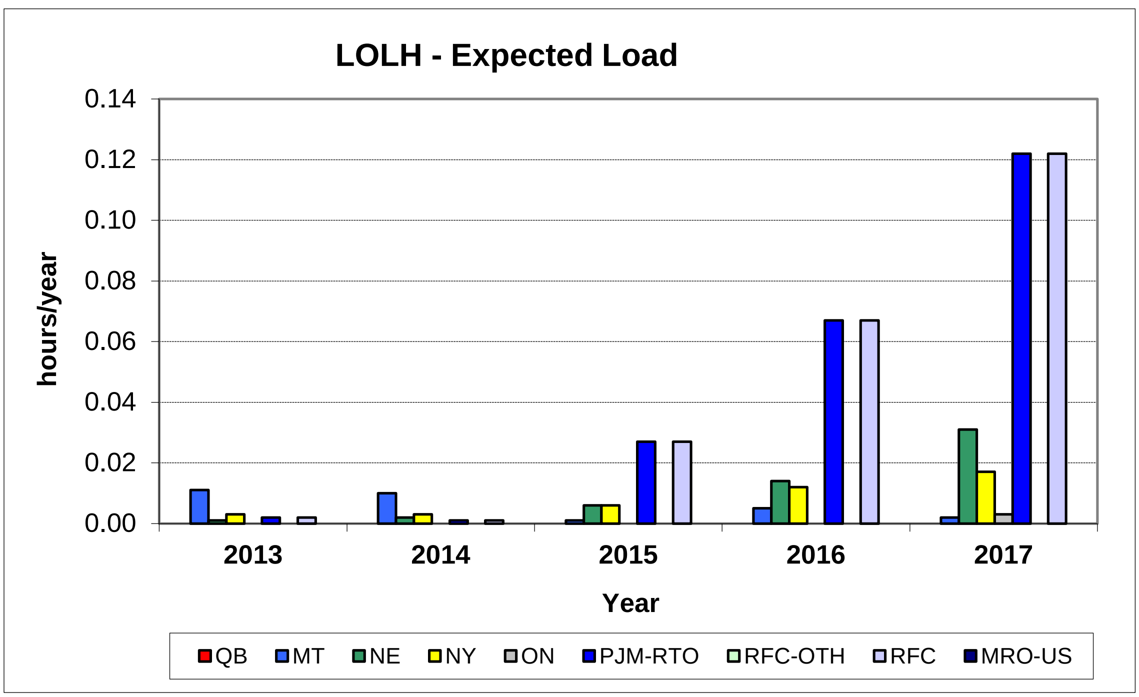

Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2013 – 2017)

Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2013-2017 period.

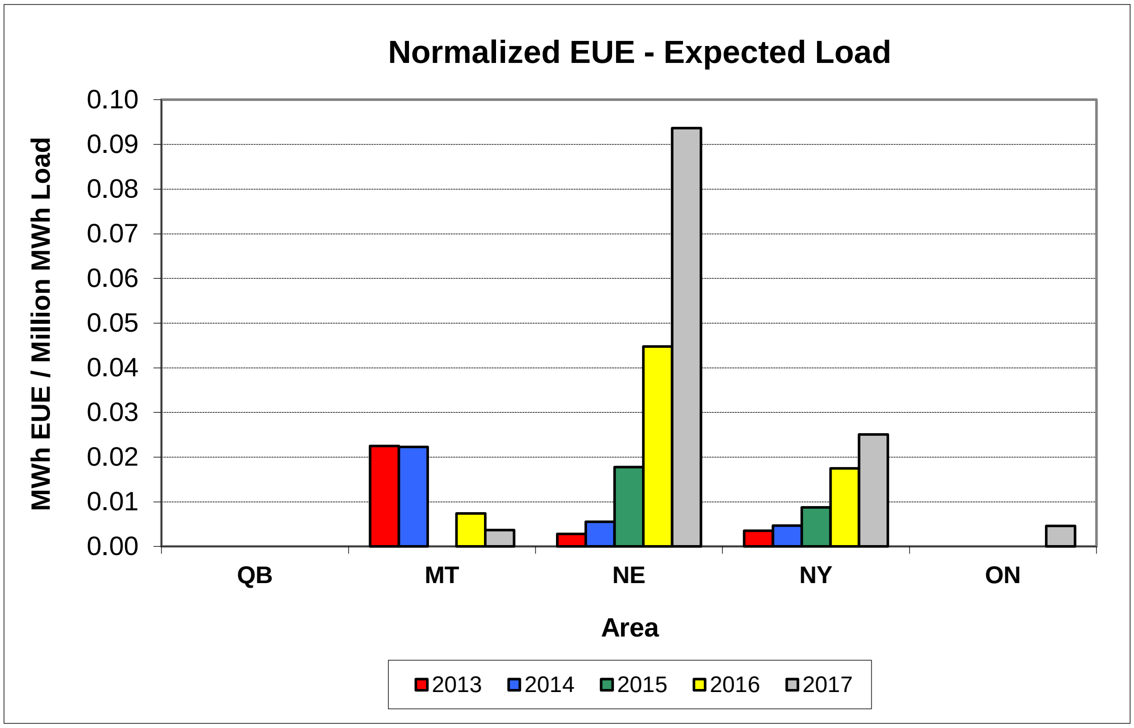

Figure 11(a) - Estimated Annual NPCC Area EUE (2013 – 2017)

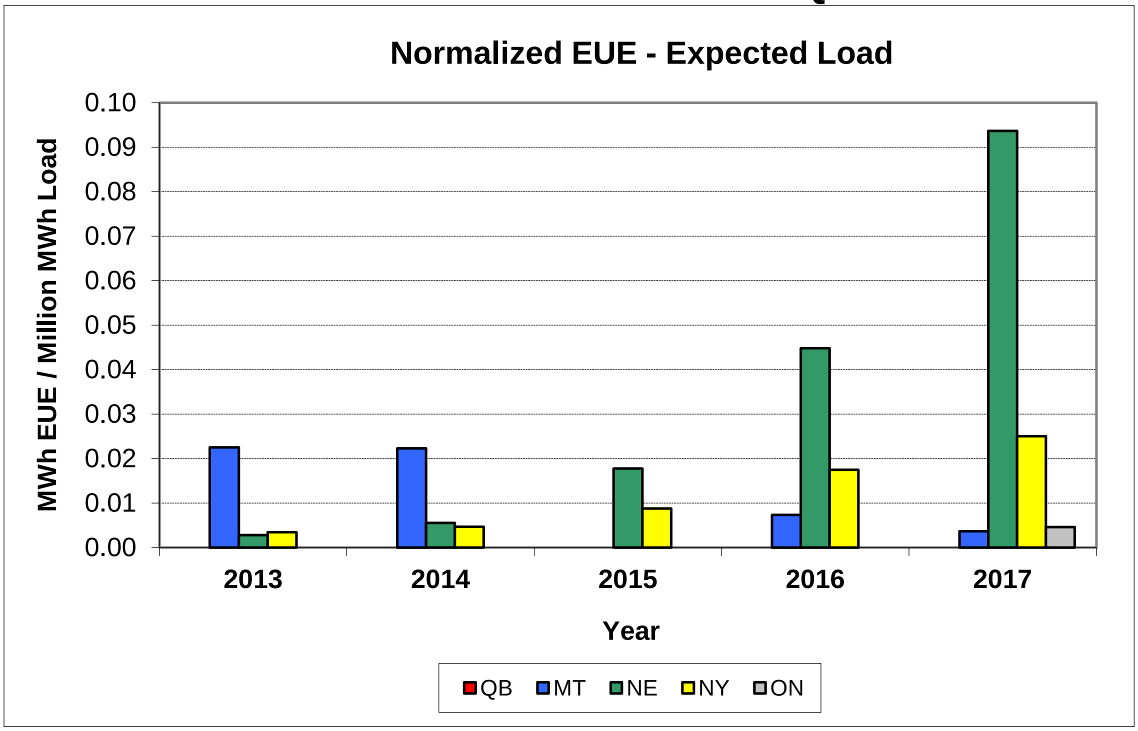

Figure 11(b) – Estimated Annual NPCC Area LOLH (2013 – 2017)

Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2013-2017 period.

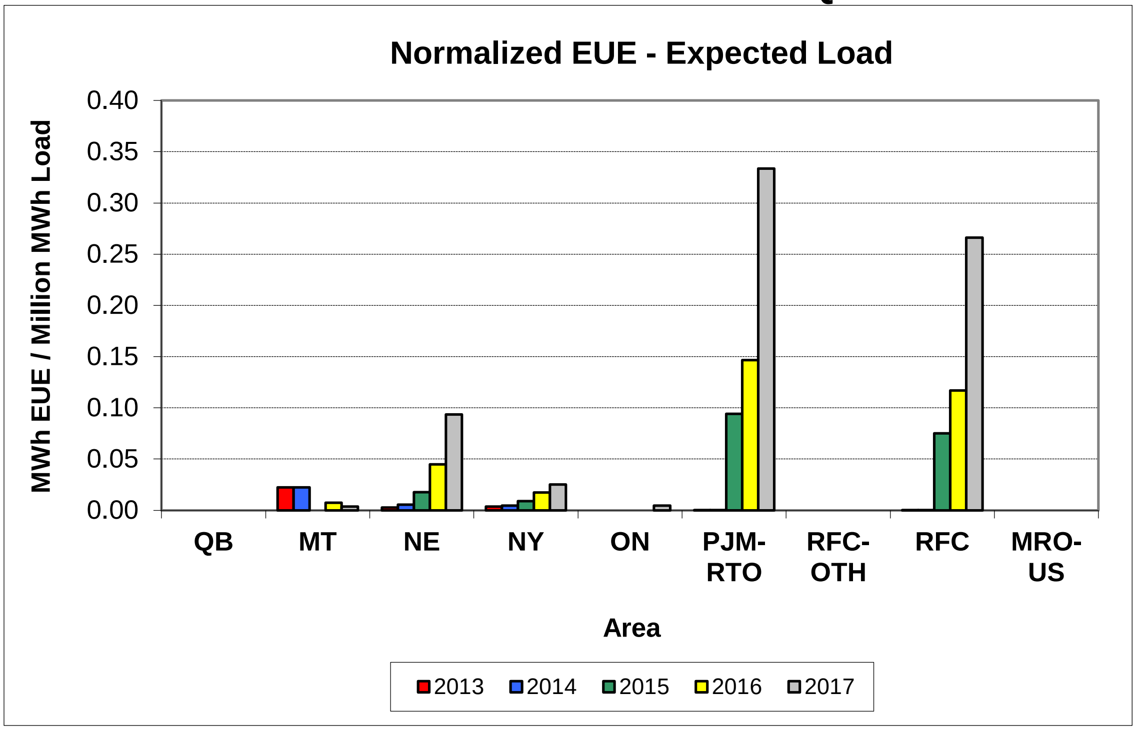

Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2013 – 2017)

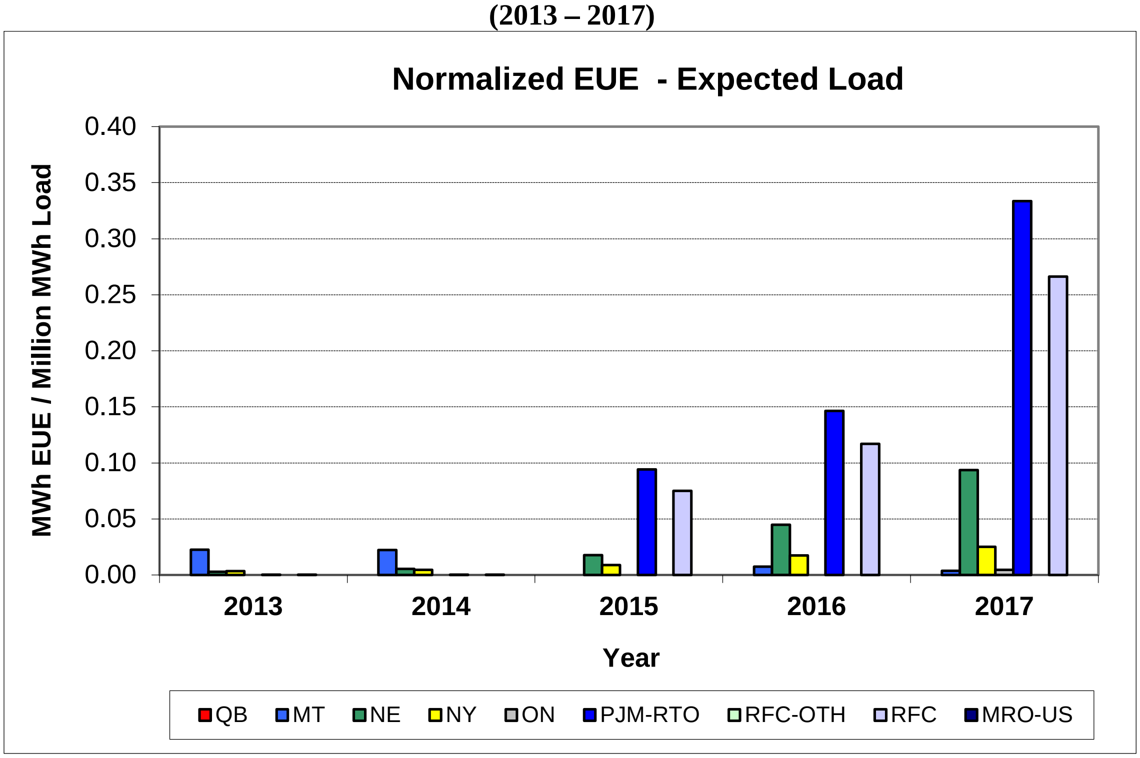

Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions

Table 24 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount5 reported in the *NERC 2012 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS calculation for the total estimated NPCC annual energy is approximately 2% higher than the corresponding sum of the NPCC Areas annual energy forecasts.

Table 24 –Comparison of Energies Modeled (Annual MWhrs)

Year	2013	2014	2015	2016	2017
Quebec					
MARS	191,415,456	193,158,912	192,986,128	193,727,648	193,306,832
2012 LTRA	187,973,154	189,428,847	190,464,234	194,009,336	194,669,649
(MARS-LTRA)	3,442,302	3,730,065	2,521,894	-281,688	-1,362,817
% (MARS-LTRA)/LTRA	1.8	2.0	1.3	-0.1	-0.7
Maritimes					
MARS	26,665,208	26,879,986	27,054,348	27,078,624	27,177,371
2012 LTRA	26,662,000	26,879,000	27,107,000	27,130,000	27,235,000
(MARS-LTRA)	3,208	986	-52,652	-51,376	-57,630
% (MARS-LTRA)/LTRA	0.0	0.0	-0.2	-0.2	-0.2
New England					
MARS	141,015,904	143,568,960	146,330,080	149,563,936	151,653,376
2012 LTRA	138,875,000	140,520,000	142,215,000	143,815,000	145,245,000
(MARS-LTRA)	2,140,904	3,048,960	4,115,080	5,748,936	6,408,376
% (MARS-LTRA)/LTRA	1.5	2.2	2.9	4.0	4.4
New York					
MARS	171,153,009	170,351,547	170,545,146	171,281,939	171,645,120
2012 LTRA	164,627,000	165,340,000	166,030,000	166,915,000	166,997,000
(MARS-LTRA)	6,526,009	5,011,547	4,515,146	4,366,939	4,648,120
% (MARS-LTRA)/LTRA	4	3.0	2.7	2.6	2.8
Ontario					
MARS	142,831,689	139,139,187	135,486,644	131,834,107	129,965,019
2012 LTRA	142,792,000	139,139,000	135,487,000	131,834,000	129,965,000
(MARS-LTRA)	39,689	187	-356	107	19
% (MARS-LTRA)/LTRA	0.0	0.0	0.0	0.0	0.0

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NPCC 2012 LONG RANGE ADEQUACY OVERVIEW

Year	**2013**	**2014**	**2015**	**2016**	**2017**
NPCC					
MARS	673,081,280	673,098,624	672,402,304	673,486,272	673,747,712
2012 LTRA	660,929,154	661,306,847	661,303,234	663,703,336	664,111,649
(MARS-LTRA)	12,152,126	11,791,777	11,099,070	9,782,936	9,636,063
% (MARS-LTRA)/LTRA	1.8	1.8	1.7	1.5	1.5

OBSERVATIONS

Figures 12(a) and 12(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

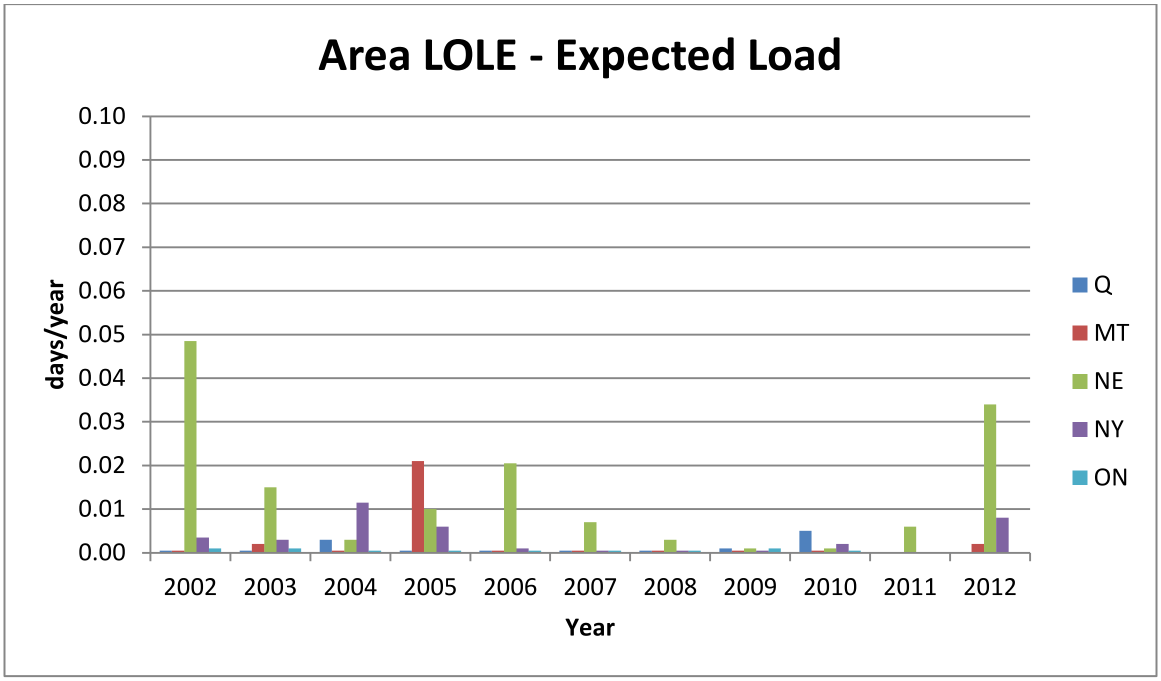

Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

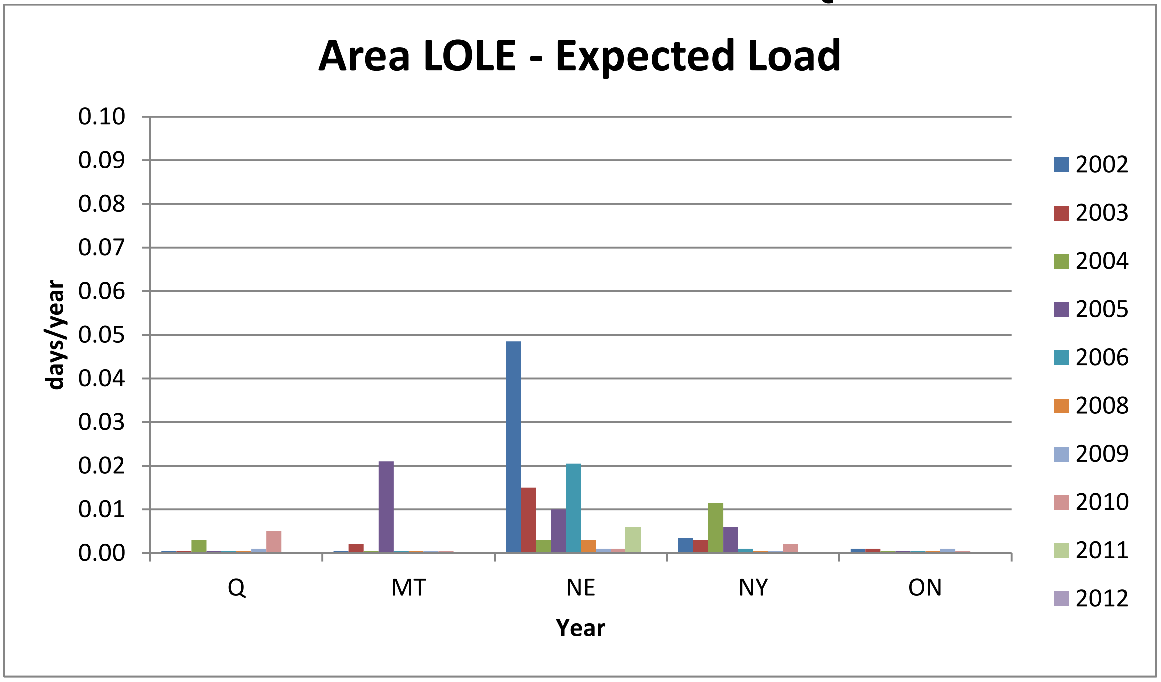

Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

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

Figures 13(a) and 13(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2013 – 2017.

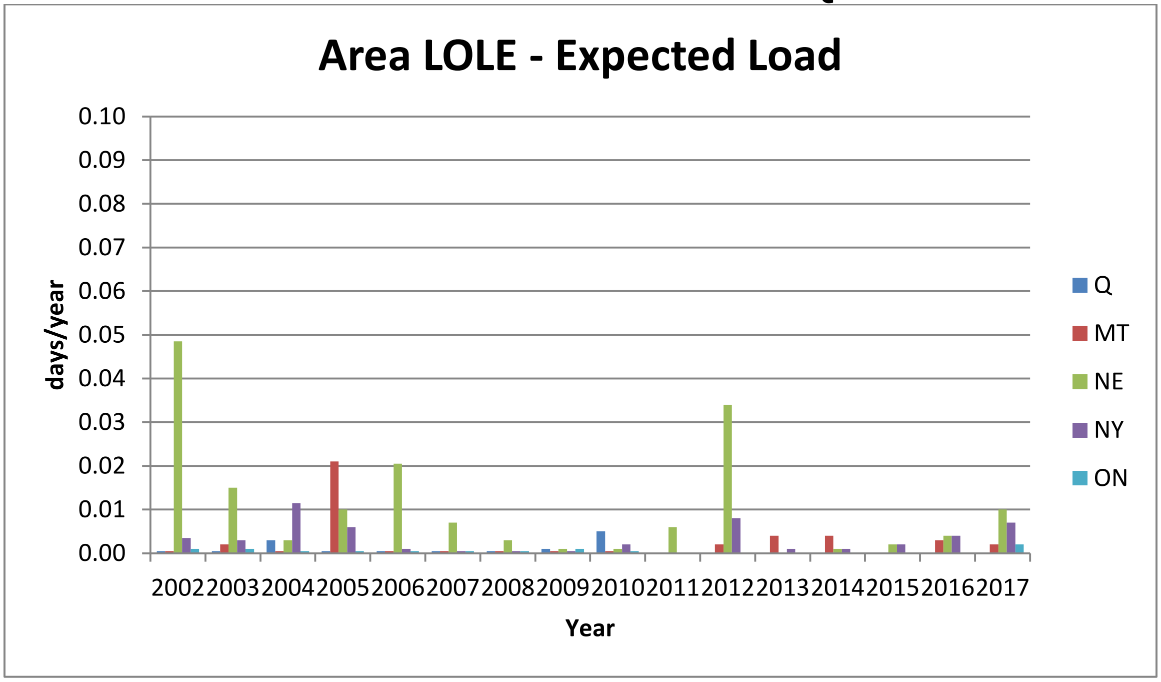

Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

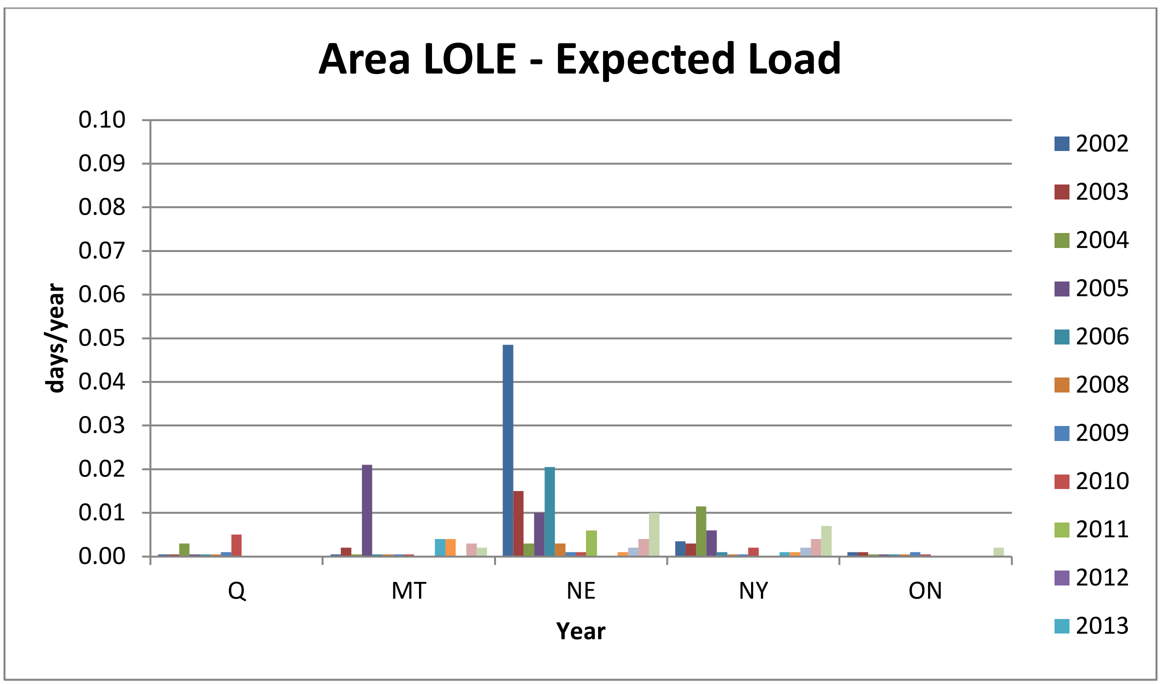

Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

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NPCC 2012 LONG RANGE ADEQUACY OVERVIEW
APPENDIX A

Objective and Scope of Work

1. Objective

On a consistent basis, evaluate the near term seasonal and long-range (five year) adequacy of NPCC Areas' and reflecting 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 expected to provide for future adequacy in the overview.

In meeting this objective, the CP-8 Working Group will use the G.E. Multi-Area Reliability Simulation (MARS) program, incorporating, to the extent possible, a detailed reliability representation for regions bordering NPCC for the 2012 -2017 time period.

2. Scope

The near term seasonal analyses will use the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2012 - 2017 time period to consistently review the resource adequacy of NPCC Areas and reflecting neighboring Regions' assumptions under Base Case (likely available resources and transmission) and Severe Case assumptions for the May to September 2012 summer and November 2012 to March 2013 winter period, recognizing:

- ✓ uncertainty in forecasted demand,
- ✓ scheduled outages of transmission,
- ✓ forced and scheduled outages of generation facilities, including fuel supply disruptions,
- ✓ the impacts of Sub-Area transmission constraints,
- ✓ the impacts of proposed load response programs; and,
- ✓ as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

Reliability for the near term seasonal analyses (2012 - 2013) will be measured by estimating annual NPCC Area LOLE and use of NPCC Area operating procedures used to mitigate resource shortages.

The long-range analysis will extend the CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2013 - 2017 time period, to consistently review the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) assumptions, recognizing the above considerations.

Reliability for the long-range (2012 – 2017) analysis will be measured by calculating the annual Loss of Load Expectation (LOLE) for each NPCC Area and neighboring Regions.

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2012.

A report of the results of the winter assessment will be published no later than June 29, 2012.

A report summarizing the results of the NPCC Long Range Adequacy Overview will be published no later than December 31, 2012.

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NPCC 2012 LONG RANGE ADEQUACY OVERVIEW

APPENDIX B

Capacity and Load at Time of Area Peak

Base Case with Composite Load Shape

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NPCC 2012 LONG RANGE ADEQUACY OVERVIEW

Base Case with Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2013								
	Jan	Feb	Aug	Aug	Jul	Jul	Jul	Jul
Capacity (MW) *	39,044	6,985	31,838	38,016	29,795	183,856	48,711	35,318
Purchase/Sale (MW)	603	-26	1,556	1,223	0	-802	0	0
Load (MW)	37,262	5,195	27,765	33,551	23,277	161,240	42,428	30,923
Demand Response (MW)	1,339	253	2,817	1,748	380	0	0	0
Reserves (%)	10.0	34	25	18	28	14	15	14
Maintenance - Peak Week (MW)	**	20	0	79	885	3	0	0
Max. Wind Capacity (MW) *	513	491	139	1,559	280	1,035	9,780	7,140
2014								
	Jan	Feb	Aug	Aug	Jul	Jul	Jul	Jul
Capacity (MW) *	39,612	6,989	31,310	38,022	27,552	184,973	49,695	36,066
Purchase/Sale (MW)	640	-26	1,658	1,197	0	-801	0	0
Load (MW)	37,748	5,219	28,275	33,463	23,081	164,869	43,276	31,541
Demand Response (MW)	1,339	252	3,397	1,748	378	0	0	0
Reserves (%)	10.2	33	22	18	19	12	15	14
Maintenance - Peak Week (MW)	**	17	0	79	851	1	0	0
Max. Wind Capacity (MW) *	715	495	139	1,565	429	1,391	9,980	7,300
2015								
	Jan	Feb	Aug	Aug	Jul	Jul	Jul	Jul
Capacity (MW) *	40,492	6,989	31,310	38,021	27,230	175,707	49,902	36,204
Purchase/Sale (MW)	399	-21	162	1,809	0	-801	0	0
Load (MW)	37,986	5,254	28,840	33,529	22,760	168,269	43,455	31,671
Demand Response (MW)	1,143	251	3,646	1,748	375	0	0	0
Reserves (%)	10.7	33	15	20	20	5	15	14
Maintenance - Peak Week (MW)	**	25	0	65	835	168	0	0
Max. Wind Capacity (MW) *	839	495	139	1,564	622	1,633	10,040	7,340
2016								
	Jan	Feb	Aug	Aug	Jul	Jul	Jul	Jul
Capacity (MW) *	40,789	6,893	31,310	38,027	25,766	176,074	50,276	36,460
Purchase/Sale (MW)	345	0	-30	1,809	0	-801	0	
Load (MW)	38,448	5,206	29,400	33,598	22,436	170,686	43,784	31,911
Demand Response (MW)	1,143	250	3,879	1,748	372	0	0	0
Reserves (%)	10.0	32	13	19	15	3	15	14
Maintenance - Peak Week (MW)	**	33	0	60	806	0	0	0
Max. Wind Capacity (MW) *	973	495	139	1,570	622	1,650	10,120	7,400
2017								
	Jan	Feb	Aug	Aug	Jul	Jul	Jul	Jul
Capacity (MW) *	41,308	6,898	31,310	38,022	24,415	176,438	51,004	37,001
Purchase/Sale (MW)	896	0	-30	1,809	0	-801	0	0
Load (MW)	38,799	5,292	29,895	33,763	22,325	172,466	44,416	32,371
Demand Response (MW)	1,132	248	4,097	1,748	371	0	0	0
Reserves (%)	11.7	30	12	19	9	2	15	14
Maintenance - Peak Week (MW)	**	40	0	60	806	0	0	0
Max. Wind Capacity (MW) *	973	495	139	1,565	622	1,650	10,260	7,500

*** Wind capacity included at maximum output for the month, not nameplate rating; demand response not included in capacity**

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