The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE Energy, and Andrew Ford, the PJM Interconnection, and thanks them for their assistance in this analysis.
TABLE OF CONTENTS

INTRODUCTION 3

MODEL ASSUMPTIONS 4
- Area Studies ................................................................. 4
- Load Representation .................................................... 6
  - Load Shape ............................................................... 7
  - Load Forecast Uncertainty ............................................. 7
- Generation ................................................................. 8
  - Unit Availability ......................................................... 8
  - Capacity and Load Summary ........................................... 8
- Transfer Limits ............................................................. 12
- Operating Procedures to Mitigate Resource Shortages ........... 13
- Assistance Priority ...................................................... 14

AREA ASSUMPTIONS 15
- Maritimes ..................................................................... 15
- New England ............................................................... 18
- New York ...................................................................... 28
- Ontario ......................................................................... 33
- Québec ........................................................................ 38

MODELING OF NEIGHBORING REGIONS ................................... 46
- ReliabilityFirst .............................................................. 47
- MRO ............................................................................ 48
- PJM-RTO ...................................................................... 48

RESULTS 51

OBSERVATIONS 60
APPENDICES

A. OBJECTIVE AND SCOPE OF WORK .................................................. 62

B. CAPACITY AND LOAD SUMMARY ................................................. 64
INTRODUCTION

This study evaluated, on a consistent basis, the long range adequacy of Northeast Power Coordinating Council’s (NPCC) and neighboring Region’s plans to meet their Loss-of-Load Expectation (LOLE) planning criteria through a multi-area 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 (GTRPMTF) with two main deliverables in the scope:

- To evaluate approaches and models for composite generation and transmission (G&T) reliability assessment.
- To 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 GTRPMTF Final Report on Methodology and Metrics was approved. The metric results described in the Final Report included the:

(i) annual Loss-of-Load Hours (LOLH),
(ii) Expected Unserved Energy (EUE),
(iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by the Working Group to conduct the simulations. The database developed by the NPCC CP-8 Working Group's "NPCC Reliability Assessment for Summer 2011", May 2011, 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 2011-2015 time period, consistent with the information reported for the NERC 2011 Long-Term Reliability Assessment.

This report is organized in the following manner: after a brief Introduction, general modeling assumptions are presented followed by a summary provided by each Area describing their specific representation. The results and observations of the Overview are then presented. The Overview's Objective and Scope of Work is shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

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1 See: http://www.npcc.org/documents/regStandards/Directories.aspx, Directory No. 1, Section 5.2
4 See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx, Appendix VIII
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

The 2010 Reliability Needs Assessment 6 (RNA), published on September 10, 2010 commences the fifth cycle of the NYISO’s reliability planning processes provided for in 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 RNA provides a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system conducted over a 10-year planning horizon.

The 2010 RNA builds upon the results and analyses contained in the NYISO’s prior Comprehensive Reliability Plans (CRP) in 2005, 2007, 2008 and 2009 respectively. The first three CRPs responded to the Reliability Needs identified by their respective RNAs. The 2009 RNA, with the reduced forecast associated with energy efficiency peak load reductions, increased generation and increased demand response, identified no Reliability Needs. The fourth CRP indicated that the system was reliable and no solutions were necessary in response to the 2009 RNA.

The 2010 RNA identified no Reliability Need, assuming that all modeled transmission and generation facilities, including Indian Point, remain in service during the next 10 years from 2011 through 2020. The study of the Base Case indicates that the baseline system meets all applicable Reliability Criteria. However pending regulatory initiatives may affect Base Case facilities and could result in unanticipated retirement of capacity in New York. The NYISO will continue to monitor these developments and will conduct appropriate reliability studies as necessary.

On January 11, 2011, the New York Independent System Operator (NYISO) issued its 2010 Comprehensive Reliability Plan (CRP), 7 a study that recommends solutions to meet New York’s future electric power needs and maintain the integrity of the state’s bulk power grid for the next ten years. The 2010 CRP is the fifth completed by the NYISO.

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The next step of the biennial New York Comprehensive System Planning Process is the completion of the Congestion Assessment and Resource Integration Study (CARIS) for economic planning. CARIS will examine congestion on the New York bulk power system and the costs and benefits of alternatives to alleviate that congestion. During the second phase of this step, the NYISO will evaluate specific transmission project proposals for regulated cost recovery.

**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 2011 RSP and other planning issues facing the New England region was held on September 8, 2011. The New England RSP11 was approved by ISO-New England’s Board of Directors on October 21, 2011.

**Ontario**

The Independent Electricity System Operator of Ontario regularly assesses the adequacy and reliability of Ontario's power system. 18-Month Outlooks are issued on a quarterly basis. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update shows over 2,500 megawatts (MW) of new and refurbished generation is expected to be connected to Ontario's bulk power system over the next 18 months. This will include the anticipated return of two refurbished Bruce nuclear units, the addition of approximately 400 MW of gas-fired generation in York Region and the construction of approximately 600 MW of grid-connected renewable generation. By February 2013, the IESO expects a combined total of more than 4,000 MW of wind and solar generation to be connected to either the high-voltage transmission grid or the low-voltage distribution system.

By December 31, 2011 the installed capacity of coal-fired generation will be reduced by 980 MW to 3,504 MW when two additional units at Nanticoke are shut down. To ensure the phase-out of coal is achieved by 2014, a number of infrastructure projects, including transmission improvements, are currently underway.

**Québec**

The Québec assumptions used in this study are consistent with its 2010 NPCC Interim Review of Resource Adequacy and the 2011 NERC Long-Term Reliability Assessment.

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8 See: http://www.iso-ne.com/trans/rsp/index.html
10 See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
The existing resources for the 2011/2012 period total 43,851 MW. Gentilly-2 nuclear generating station refurbishment (675 MW) will be effective during the period 2012-2014. Gentilly-2 is expected to be back in service for the 2014/2015 peak period.

**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 Maritimes assumptions used in this study are consistent with its most recent NPCC Review of Resource Adequacy.  

The Maritimes Area is expected to comply with the NPCC resource adequacy criterion that requires a loss of load expectation (LOLE) value of less than 0.1 days/year for all years from 2012 to 2015, varying between 0 to 0.002 days/yr for the base load forecast with load forecast uncertainty. The Maritimes Area is also expected to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 40% and 42%.

**PJM-RTO**

The annual PJM Reserve Requirement Study (RRS) 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 ReliabilityFirst 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.

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

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 from the 2003 and 2004 loads the load growth that had occurred from 2002, 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 2001, 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, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are shaded in Table 1.

Table 1
Per Unit Variation in Load Assumed (Month of January 2012)

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>MT</td>
<td>1.1000 1.1000 1.0500 1.0000 0.9500 0.9000 0.9000</td>
</tr>
<tr>
<td>NE</td>
<td>1.0934 1.0383 0.9971 0.9635 0.9402 0.8500 0.8000</td>
</tr>
<tr>
<td>NY</td>
<td>1.0430 1.0310 1.0160 0.9980 0.9750 0.9440 0.9050</td>
</tr>
<tr>
<td>ON</td>
<td>1.0835 1.0557 1.0278 1.0000 0.9722 0.9443 0.9165</td>
</tr>
<tr>
<td>QC</td>
<td>1.0854 1.0641 1.0427 1.0000 0.9573 0.9360 0.9146</td>
</tr>
<tr>
<td>Prob.</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
</tbody>
</table>

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 2012-2016 period. Area peak load is shown against the initial area capacity, adjusted for purchases, retirements, and additions. 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
(reflects the retirement of Salem Harbor units 3 and 4)
Figure 3 – New York Area Capacity and Load

Figure 4 – Ontario Capacity and Load
Figure 5 – Québec Capacity and Load

Figure 6 – PJM-RTO Capacity and Load
Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the 2012-2016 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 - ReliabilityFirst Corp.
MRO - Midwest Reliability Organization  Que - Québec Centre  MT - Maritimes Area

* The actual transfer capability is 1,000 MW. However, it was modeled as 700 MW to reflect limitations imposed by inter-regional New England constraints that are currently under review by ISO New England.
** ISO-NE assumes imports of 3 MWh on these ties in their planning studies.
Operating Procedures to Mitigate Resource Shortages

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

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

Table 2 summarizes the load relief assumptions modeled for each NPCC area. The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 2 was a reasonable approximation for this analysis.
### Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month Load Relief Assumptions - MW

<table>
<thead>
<tr>
<th>Actions</th>
<th>MT (Feb)</th>
<th>NE (Jul)</th>
<th>NY (Jul)</th>
<th>ON (Aug)</th>
<th>QC (Jan)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus Appeals</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>148</td>
<td>1,073</td>
</tr>
<tr>
<td>RT-DR/SCR/EDRP</td>
<td>-</td>
<td>866</td>
<td>143</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SCR Load /Man. Volt. Red.</td>
<td>-</td>
<td>5.55%</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>162</td>
<td>600</td>
<td>600</td>
<td>473</td>
<td>500</td>
</tr>
<tr>
<td>3. Voltage Reduction</td>
<td>-</td>
<td>416</td>
<td>1.34%</td>
<td>-</td>
<td>250</td>
</tr>
<tr>
<td>Interruptible Loads</td>
<td>376</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>457</td>
<td>-</td>
<td>-</td>
<td>1,080</td>
<td>750</td>
</tr>
<tr>
<td>RT-EG</td>
<td>-</td>
<td>389</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>-</td>
<td>-</td>
<td>231</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>5. 5% Voltage Reduction No 10-min Reserves</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2.60%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>-</td>
<td>1,200</td>
<td>1,200</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

### 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.

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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.
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 dependant 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 10-years.

Demand

The forecast average annual on-peak demand growth rate is negative, between -0.1 and -0.2 percent, from 2011-2021. 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 a long-term average of temperatures at time of peak, along with analyses of sales history, 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. The 2010 peak was inflated at a
nominal rate of 0.5 percent. 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.

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 nongovernment, 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 both retain an independent savings verification consultant to verify the savings reported by the independent evaluation consultant.

One of the Demand Response programs currently used in the Maritimes Area but most predominantly in Nova Scotia is interruptible demand. For 2011-2012, the interruptible demand forecast for the peak month is 371 MW, which represents 7 percent of the peak demand forecast. Other Demand Response programs used in Nova Scotia are primarily rate design-driven and along with interruptible pricing for large industrials, include time of day pricing for residential customers with electric thermal storage home heating equipment, and the Extra Large Industrial Interruptible two part Real-time Pricing rate for NSPI's two largest customers.

In Nova Scotia, a 5 percent voltage reduction is implemented at selected substations (approximately 1-5 MW). Interruptible demand is reported separately but other programs are incorporated directly into the load forecast. In Nova Scotia, it is anticipated that more future Demand Response programs might be contemplated by the DSM administrator but none have yet been planned.

While demand side management resources are considered for meeting regional targets for greenhouse gas reductions, they are not currently counted towards regional renewable portfolio standards. The Maritimes Area uses a load forecast uncertainty representing the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

**Capacity Transactions on Peak**
The Maritimes Area has a total supply of 366 MW of capacity contracted from Québec for the 2011-2012 peak period. There are currently no capacity imports scheduled after
that time. None of the capacity imports for the Maritimes Area are related to Reserve Margins or tied to specific generating units.

Transmission
NB Power is planning to add a new 1 mile 138 kV line in late 2011 to serve distribution load in the Newcastle area of the province. Nova Scotia is planning the following 138 kV transmission line projects:

- Near Canaan Rd - this line is 27 miles in length, and targeted for 2011
- Near New Minas - this line is 4 miles in length, and targeted for 2012
- Near Eastern Passage - this line is 7 miles in length, and targeted for 2013

New Brunswick is currently studying a 103 Mile 345 kV transmission line project between Coleson Cove New Brunswick and Salisbury New Brunswick twinning an existing circuit to better serve growing loads in southeastern NB. An interprovincial tie line from Salisbury New Brunswick to Onslow Nova Scotia could allow for more renewable generation sources to be incorporated into the Maritime generation mix and increase the tie capacity allowing for better sharing of reserves. This line would be 100 miles in length, and targeted for a 2016 in-service date.

Generation
Figure 8 depicts the Maritimes area resource capacity mix by fuel type for the year 2011 on an capacity basis, representing 31% oil, 24% coal, 19% hydro, 9% nuclear, 7% gas, 5% oil/gas, 4% wind (derated), and 1% biomass generation.

![Maritimes Capacity Mix by Fuel Type - 2011](image)

*Figure 8 – Maritime Area Capacity Mix by Fuel Type for 2011*
Wind project capacities modeled in resource adequacy calculations for New Brunswick and northern Maine (40 percent of nominal capacity during the winter peak period) are based on results from the September 2005 NBEO report, “Maritimes Wind Integration Study.” This report showed that the effective capacity from wind projects, and their contribution to LOLE was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. In PEI wind capacity was based on actual capacity factors for the wind generators during winter and summer peak load periods. In Nova Scotia, the capacity contribution of wind projects during the peak is based on a three year rolling average of the winter peak period actual capacity factor (combined with the annual forecasted capacity factor, if in service less than three years). This is based on an agreed formula between the Renewable Energy Industry Association of Nova Scotia and NSPI.

New Nova Scotia wind resources are assigned an on-peak capacity based on the forecast winter capacity factor. 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. In Nova Scotia, increased amounts of renewable generation will be connected to the distribution system through the Community Feed-in-Tariff as outlined in the Province’s Renewable Electricity Plan in April 2010.

New England
ISO New England Inc. (ISO-NE) forecasts no major reliability issues with respect to fuel supply, availability of both supply or demand-side resources, or the capability of the regional transmission system to serve the projected seasonal peak demands and energy requirements of the six-state New England sub-region.

New England is a summer-peaking system. The 2010 summer actual peak demand was 27,102 MW which was 88 MW lower than the last year’s 2010 projection for the 2010 summer peak demand of 27,190 MW. A warmer than normal 2010 summer season in New England produced several peak demand days. The Total Internal Demand projected for the 2011 summer is 27,550 MW and is 31,215 MW for the 2020 summer. This year’s forecast of the ten-year (2011-2020) 50/50 summer peak demand compound annual growth rate is 1.4 percent.

For the 2011 summer, the Existing-Certain capacity totals 29,590 MW which is 763 MW lower than last year’s value of 30,353 MW when demand resources are not included. Approximately 437 MW of Future Capacity Additions are projected to be

commercialized by the 2021 summer. In addition, demand resources are expected to grow by 1,364 MW over the current capacity of 2,035 MW. The only significant retirement of regional capacity is the submittal of a non-price retirement for the entire Salem Harbor station, currently rated at approximately 745 MW. Salem Harbor units 1 & 2 (158 MW) are scheduled to retire by the end of 2011. Salem Harbor 3 & 4 (587 MW) are scheduled to retire by June 1, 2014. ISO-NE and regional Transmission Owners have been studying this retirement. To ensure the continued reliability of the electric system within northeastern Massachusetts, transmission enhancements are under investigation for expedited installation.

The NERC reference Reserve Margin for a thermal power system like New England is 15 percent; however, New England does not have a target Reserve Margin. New England’s 2011 summer Anticipated Reserve Margin is 18.9 percent, which is 3.9 percent above the NERC reference Reserve Margin. This Reserve Margin remains above the 15 percent reference Reserve Margin through 2014 and then begins to decrease. Based on the forecast of the sub-region’s Net Installed Capacity Requirement (Net ICR) for 2020, it is estimated that New England’s 2020 summer Reserve Margin would be no lower than 14.2 percent.

ISO-NE’s Regional System Plans (RSPs) identify the sub-region’s needed transmission improvements over a ten-year period. The current plan builds on the results of previous RSPs and other regional activities. The transmission projects have been developed to coordinate major power transfers across the system, improve service to demand, and meet transfer requirements with neighboring balancing authority areas. The only significant transmission project that has been placed in service since the prior year is the Vermont Southern Loop 345 kV line.

Transmission plans continue to be developed to serve demand growth throughout the New England sub-region. ISO New England has identified projects that address transmission system performance issues, either individually or in combination. Some of the projects address sub-regional reliability issues and also have the ancillary benefit of improving the performance of major transmission corridors and thus the overall performance of the system.

Transmission projects are developed to serve the entire New England sub-region reliably and are fully coordinated with other regions. Over the course of the assessment period, the most significant issues facing New England have been to maintain the general performance of the long 345 kV corridors, maintain the reliability of supply to serve demand, and develop the transmission infrastructure to integrate generation throughout New England. The region faces thermal and voltage performance issues, stability concerns, and is reliant on several Special Protection Systems (SPS) that may be subject to incorrect or undesired operation. System upgrades, which are either in progress or have been recently completed, provide significant relief for these areas.
Five issues have been identified that could possibly impact future New England system reliability. These are categorized into the short and long-term timeframes. The short-term challenges involve (1) resource performance and flexibility, and, more specifically, the uncertain performance of aging supply-side resources, the uncertain performance of new demand resources, and lack of comparability between new demand-side and supply-side resources. The failure of resources to perform and concerns over system flexibility also heightens concerns about fuel diversity. Specifically, (2) increased reliance on natural gas-fired capacity poses a risk to the New England electric system, as sufficient natural gas may not be available during periods of very high seasonal demand (winter) or when the regional natural gas transportation system is experiencing problems.

The longer-term challenges are the result of significant changes to New England’s power system which will be driven by (3) the retirement of fossil-fired generators, which is likely as a result of economic factors and environmental regulations, and (4) the integration of a greater level of variable resources, primarily renewable (i.e., wind and solar) energy resources. In addition, ISO-NE and some stakeholders have noted that wholesale markets may not adequately reflect the rapidly-evolving reliability needs that are identified through reliability planning and system operations, and that better (5) alignment of planning and markets could create more opportunities for market resources to meet reliability needs, thereby more efficiently managing accelerated resource turnover.

ISO New England has developed a sequence of solutions to address these challenges. The first stage of the solution includes enhancing resource performance and accountability, improving system reserves and flexibility, and implementing changes to ensure that resource attributes properly reflect constraints that may limit availability or performance. The second stage of the solutions, which would be addressed over a longer time frame, involves establishing methods for identifying and evaluating in a consistent manner, the various potential transmission, generation, and demand solutions for identified reliability needs. ISO New England would also make design improvements to its capacity and reserve markets to procure resources with more precision in particular geographical areas or with desired characteristics. Finally, a process would be established for regularly evaluating and identifying the level of required deliverability and diversity in the resource mix, and how such needs could be translated into capacity and reserve market product definitions and performance requirements.

**Demand**

A continuation of the economic downturn has again lowered this year’s forecast for summer peak demand and energy use when compared to last year’s forecast. The projected 2011 summer peak demand forecast is 27,550 MW. This year’s forecast of the
10-year (2011-2021) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.24 percent, slightly lower than 2010 projections. The key factor leading to the lower summer peak demand forecast is that the economic downturn has significantly impacted the actual summer peak and energy demand within the New England subregion, which results in approximately a one year delay in achieving the same demand levels that had been previously predicted.

The projected 2011 winter peak demand forecast is 22,255 MW. This year’s forecast of the 10-year winter peak demand CAGR is 0.5 percent, which is the same as last year’s. The forecast for winter peak demand is slightly higher (by 170 MW) than last year’s forecast by the end of the forecast period based on updated historical demands and economic and price of electricity forecasts. The winter peak is less weather sensitive than the summer peak, closely linked to residential demand (the convergence of darkness and dinner), and less impacted by the recession.

This year’s forecast of the 10-year net annual energy CAGR is 1.1 percent, which has increased from last year’s forecast of 0.9 percent. However, the overall forecast for net annual energy use is again lower than last year’s forecast due to the economic downturn. 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 resources are considered capacity resources in New England’s FCM. Under FCM, there are passive and active demand resources. The active demand resources can be triggered by ISO-NE in real time under ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP 4) to help mitigate a capacity deficiency, or dispatched day-ahead to mitigate a projected capacity deficiency.

As part of the qualification process to participate in a Forward Capacity Auction, any new demand resource must submit detailed information about the project, including
location, project description, estimated demand reduction values, and projected commercial operation dates along with a project completion schedule. In addition, new demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. ISO-NE has the right to audit the records, data, and actual installations to ensure that the Energy Efficiency projects are providing the demand reduction as contracted. ISO-NE tracks the project against their submitted schedules, thereby taking a proactive role in monitoring the progress of these resources to ensure they are ready to reduce demand by the start of the applicable FCM commitment period.

The demand resources that have won the bids that entitle them to supply capacity to the New England capacity market through the first four forward capacity market auctions are: 1,824 MW of demand resources (560 MW of passive and 1,264 MW of active) available in July 2010, 2,035 MW by 2011 summer (774 passive, 1,261 active), 2,606 MW in 2012 summer (960 passive, 1,646 active), 3,003 MW in 2013 summer (1,148 MW passive, 1,855 MW active), and 3,399 MW in 2014 summer (1,398 MW passive, 2,001 MW active), which are then held constant through the 2021 summer.

In addition to reliability-based DR programs, ISO-NE administers a price-response DR program where demand voluntarily interrupts based on the price of energy. As of May 2011, there were approximately 61 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

Although several types of demand-side management resources (such as behind the meter small run of river hydro units) can be used to satisfy state-mandated renewable portfolio standards (RPS), ISO-NE does not require that information be submitted in order to participate in applicable markets.

ISO-NE addresses peak demand uncertainty in two ways:

1. **Weather** – Annual peak demand distribution forecasts are made based on 40 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded).\(^\text{18}\)

2. **Economics** – Alternative forecasts are made using high and low economic scenarios.

**Generation**

Figure 9 shows the aggregate capacity available at peak for the 2011 summer, representing 42.5% gas, 22.2% oil, 14.5% nuclear, 8.3% coal, 5% pumped storage hydro, 4% hydro, and 3.1% renewable generation.

\(^\text{18}\) On an annual basis, the 50/50 reference peak has a 50 percent chance of being exceeded, and the 90/10 extreme peak has a 10 percent chance of being exceeded.
Under the New England Forward Capacity Market (FCM), regional capacity that has a capacity supply obligation (CSO) is reported within this assessment as *Existing-Certain* capacity and all remaining non-CSO capacity is reported as *Existing-Other* capacity. Since ISO-NE has already procured the CSO for the 2014-2015 Capability Period, regional generating capacity through that time period is identified within one of these two categories. Beginning with the 2015 summer, those prior CSOs are then held constant throughout the assessment period.

For August 2011, ISO-NE reports:
- 34,477 MW of capacity, which includes 29,590 MW of *Existing-Certain* capacity, 2,227 MW of *Existing-Other* capacity, 625 MW of capacity derates, 2,035 MW of Demand Side Management (DSM) resources, and 0 MW of *Existing-Inoperable* capacity.
- 116 MW of nameplate wind capacity, which includes 26 MW of *Existing-Certain* wind capacity expected on-peak along with a 90 MW on-peak derate of *Existing-Other* wind capacity.
- 147 MW of *Conceptual* capacity on the system which includes 7 MW of hydro resources.

By August 2021, ISO-NE reports:
- an additional 495 MW of *Future-Planned* nameplate wind capacity with 100 MW expected on-peak along with a 395 MW on-peak derating. Planned wind capacity is rated differently from its nameplate capability due to Market Rules for rating intermittent supply-side resources, which also takes into account the site-specific...
wind characteristics of those projects. In 2021, Conceptual wind capacity is 2,525 MW, which is based on nameplate ratings, and has target in-service dates of 2012 through 2016.

- An additional 6,428 MW of Conceptual capacity potentially on the system. This amount also includes on-peak Conceptual capacities of 2,525 MW of wind, 0 MW of solar, 33 MW of hydro-electric, and 357 MW of biomass. The on-peak capacity ratings of variable or intermittent resources are determined from the Market Rules pertaining to qualification determination of capacity within the FCM.

ISO-NE’s Reserve Margin calculations include Future Capacity Additions that are projected to begin commercial operation by the end of each year. If the new project’s in-service date is prior to August 1st of that year that capacity is included within the Future-Planned capacity for the summer of the year, otherwise it is included within the Future-Planned capacity for the winter of the following year. This information is based on either the date specified in a signed Interconnection Agreement (IA) or discussions with ISO-NE indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the Future-Planned capacity additions are new projects that have contractual obligations within the ISO-NE FCM for the years 2011-2014. Conceptual capacity is subsequently identified as all the capacity remaining within the ISO-NE Generation Interconnection Queue that has not been designated as Future-Planned capacity, through the selection process identified above.

ISO-NE has a total of 7,992 MW of projects categorized as either Future-Planned capacity or Conceptual capacity within its Generator Interconnection Queue, with in-service dates ranging from 2011 to 2014. Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in-service dates of 2011 or 2012, some of those projects have not demonstrated viable precommercial activities and have therefore been categorized as Conceptual capacity. The Queue projects were included in the Future-Planned category if they had an FCM obligation or were projected to be in service by 2011 summer. All other Queue projects were treated as Conceptual.

A 20 percent Confidence Factor has been applied to the amount of projected Conceptual capacity resources. This 20 percent Confidence Factor represents the amount of Conceptual capacity that may become commercialized within the subregion, starting in winter 2011-2012. This 20 percent Confidence Factor is held constant going forward in time. In the 2021 summer, the total amount of Conceptual capacity resources is 6,428 MW and applying the 20 percent Confidence Factor equates to approximately 1,286 MW.
Capacity Transactions On-Peak

Imports

Firm summer capacity imports amount to approximately 1,236 MW in 2011, 1,631 MW in 2012, 1,746 MW for 2013, 1,851 MW in 2014 and 342 MW in 2015. The capacity imports for 2011 through 2014 reflect the results of the appropriate FCAs. Since the FCA imports are based on one-year contracts, beginning in 2015 the imports reflect only known, long-term ICAP contracts. Firm summer capacity imports are 120 MW in 2016 and then level off at 95 MW for the 2017 through 2021 summers. If the imports that cleared in the 2014 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or demand-side resources. There are no Expected or Provisional capacity imports projected for the assessment period.

The entire amount of ICAP imports is backed by Firm contracts for generation and the imports under the FCM are import capacity resources with an obligation for the 2011-2014 commitment periods. Although there is no requirement for those imports to have Firm transmission service, it is specified that deliverability of Firm imports must meet New England delivery requirements and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of Firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-Firm transmission services. Import assumptions are not based on partial path reservations.

Exports

For the 2011 summer, ISO-NE reports a Firm Capacity Sale to New York (Long Island) of 100 MW, anticipated to be delivered via the Cross-Sound Cable (CSC). This Firm capacity sale is held constant through the assessment period. It should be noted that there is no Firm transmission arrangement through the New England Pool Transmission Facilities system associated with this contract. There are no Expected or Provisional Capacity Exports projected for the assessment period. Export assumptions are not based on partial path reservations.

Transmission

ISO New England 2011 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.

Currently, there are no transmission constraints which prevent the system from being operated in a manner which 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. No additional significant substation equipment such as SVC, FACTS controllers or HVDC is currently planned to be added to the system.

Maine
The Maine Power Reliability Program (MPRP) proposes numerous system additions to address reliability concerns. At a high level, these upgrades will create a new 345 kV path, extending from the Orrington substation in central Maine to the Three Rivers switching station located in southern Maine. This project also adds a number of 345/115 kV autotransformers and creates a new 115 kV path into western Maine. Until the MPRP is placed in service, which is anticipated to occur in 2014, system operators will rely heavily on available resources and SPS in the area to ensure the reliability of the system.

New Hampshire
A 10-year study of the New Hampshire area has initially identified the potential for system concerns throughout much of the state for numerous different contingencies and resource outages. The more significant concerns are related to serving the southern and seacoast areas, which are served from a limited number of autotransformers and insufficient 115 kV networks. Further concerns are related to moving power into central New Hampshire, which is served through a 115 kV path and serving northern New Hampshire following the loss of the single 230/115 kV autotransformer at Littleton, NH. These concerns are addressed through the planned addition of new autotransformers in the seacoast, southern and northern areas, coupled with new transmission. The exact configuration of the new transmission is under review.

Vermont
A 10-year study of the Vermont area has identified the potential for system concerns moving power through the state for various future contingencies. Due to limited generation supplies and a significant demand concentration in the northern part of the state, power must be imported over significant distances to serve this area. Therefore, when either a southern 345 kV line or a key 345/115 kV autotransformer in the state is lost, the next critical contingency would result in numerous reliability concerns in Vermont, as well as electrical facilities in neighboring states. Solutions to these concerns include providing additional reactive support, adding new autotransformers, reconductoring a number of 115 kV lines, or adding a new 230/345 kV circuit into Vermont.

Connecticut
The original New England East - West Solution (NEEWS) studies included the evaluation of both the ability of the system to move power from East to West across southern New England and the ability to move power into and across Connecticut. Past analyses had indicated that Connecticut would need either transmission improvements or over 1,500 MW of supply or demand-side resources by 2016. Past studies also showed
that Connecticut had internal transmission elements that limited east–west power transfers across the central part of the state. The movement of power from east to west in conjunction with higher import levels to serve Connecticut had resulted in overloads of transmission facilities located within the state.

Updated transmission assessments have shown that resources planned and obligated by contract for Connecticut are sufficient to meet reliability requirements until about 2015, assuming no supply-side resource retirements. With the addition of significant resources in the west, a more immediate need now exists for an improvement in the west to east transfer capability, as opposed to the original east to west need. In the absence of additional resources, the proposed solution involves new interstate 345 kV transmission lines from western Massachusetts into Connecticut and from central Massachusetts into Rhode Island and then into eastern Connecticut.

**Southwest Connecticut**
Issues identified within the long-term reliability Needs Assessment for the area of southwest Connecticut consist of thermal overloads and low voltage violations. Alternatives to address these concerns and deficiencies are under study.

**Massachusetts**
**Boston Area**
A long-term reliability Needs Assessment has been completed for the Greater Boston area. Various transmission contingencies result in overloads of transmission facilities and low voltages within the area. Alternatives under consideration consist of a mix of new 345 kV and 230 kV transmission lines as well as 345/230 kV and 230/115 kV transformation. Preliminary solutions to address concerns in the northern and southern portions of Boston have been presented to the stakeholders and solutions for the central area are currently under study. Complete solution development is currently planned to be finished by the end of 2011. Some portions of the solutions are being expedited to address near-term reliability concerns.

**Berkshire County/Pittsfield Area**
A Needs Assessment has identified needs for the Berkshire County/Pittsfield area within western Massachusetts. Under certain system conditions, the study identified overloads on various 115 kV transmission lines and the 345/115 kV autotransformer at Berkshire. Low voltage violations were observed at several substations in the area. Possible solutions to these issues include adding 345/115kV autotransformers, upgrading long segments of old 115 kV transmission lines, and installing additional capacitors to mitigate both thermal and voltage concerns. The preferred transmission solution has been finalized, with the in-service date for the transmission upgrades targeted for 2014.
Springfield Area
The NEEWS studies, resulting in part in the Greater Springfield Reliability upgrades, have found that local double-circuit tower outages, stuck-breaker outages, and single-element outages result in severe thermal overloads and low voltage conditions. These overloads are exacerbated when Connecticut transfers increase, especially with a major 345 kV line out of service. The proposed solution eliminates a number of multi-circuit towers in the area and installs a new 345 kV line between Ludlow, Massachusetts and north-central Connecticut. These upgrades are under construction with a targeted in-service date of 2014.

Rhode Island
The Greater Rhode Island studies, in conjunction with the NEEWS studies, have identified significant thermal constraints on the 115 kV system. The outage of any one of a number of 345 kV transmission lines results in limits to power transfer capability into Rhode Island. With a line out of service, the next critical contingency would result in numerous thermal and voltage violations, and possibly the shedding of over 500 MW of demand. This could be resolved by transformer additions, a new 345 kV line between West Farnum and Kent County, and the additional central Massachusetts to Connecticut 345 kV line (mentioned above) being looped into the West Farnum substation. Presently there are no significant concerns over meeting target in-service dates of the transmission projects. However, if the implementation of these projects is delayed, interim measures will be taken.

New York
The 2011 long-term forecast projects a higher growth rate in Total Internal Demand, compared to last year. The primary drivers for future growth are the increases in population and the economy. New York is promoting a statewide Energy Efficiency policy that is projected to decrease load. Existing capacity resources for 2011 totals 38,887 MW, with Future-Planned capacity additions amounting 5,589 MW, of which 1,533 MW are wind units.

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 2011-2020 timeframe within the NYCA.
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,\(^2\) 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 annual average growth rate was 0.64 percent from 2009 to 2018. This year's annual average growth rate is 0.67 percent from 2011 to 2021. The slight difference between the 2010 forecast is due to the recovery from the recession in the short-term and additional Energy Efficiency impacts.

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. 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.

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.

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**

Figure 10 represents the existing resources in the New York Control Area with a breakdown by fuel type and as published in the NYISO’s 2011 Load and Data Report (Gold Book); representing 17% gas, 9% oil, 38% gas & oil, 6% coal, 14% nuclear, 4% hydro (pumped storage), 11% hydro, 1% wind and 1% other (methane, refuse, solar, and wood) generation.

![New York Capacity Mix by Fuel Type - 2011](image)

Figure 10 – New York Area Capacity Mix by Fuel Type for 2011

The NYISO maintains a list of proposed generation and transmission projects in the NYISO interconnection process. The interconnection process is a formal process set forth in the NYISO Open Access Transmission Tariff (OATT) by which the NYISO evaluates the impact of proposed transmission and generation projects on system reliability.

Generation that is identified as Future-Planned are the resources that have met sufficient milestones for inclusion in the 2011 Gold Book while the resources identified as Conceptual have not achieved these milestones. While these Conceptual resources are at various stages of study in the NYISO’s interconnection process, at this time the NYISO cannot determine with any certainty which of these projects will proceed to fruition as planned. Currently, there are no planned retirements scheduled over the assessment period.

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period. There were 227 MW of retired generation since the publication of the 2010 Gold Book.

**Capacity Transactions on Peak**

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. For 2011/2012, the amount is 2,730 MW. Except for grandfathered contracts, these import rights are allocated on a first-come, first-served basis.

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.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA 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. Capacity transactions associated with a UDR are considered confidential market data. Only net capacity import totals can be provided to maintain market confidentiality.

New York resources that have sold capacity to an external control area are not qualified to participate in the NYISO ICAP Market, and are not counted as resources eligible to meet the New York’s LOLE reliability criterion for the period the capacity is sold.

**Transmission**

Con Edison’s M29 project consists of a 345 kV cable from Sprainbrook to Sherman Creek across the Dunwoodie South Interface. This project entered service in early 2011. Con Edison is also increasing the rating of two 345 kV cable circuits between Farragut and East 13th St. by installing refrigerated cooling in 2011. Additional local transmission owner plans include reinforcement of the sub-transmission system by Rochester Gas & Electric and Orange & Rockland Utilities.

The interface into southeast New York and New York City could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth. These scenarios are monitored by the NYISO, and if any happen, the NYISO will determine whether there will be a significant reliability impact. If the impact is imminent, the NYISO will request that the New York Transmission Owners (TOs) implement a Gap Solution under the Comprehensive System Planning Process (CSPP). If a significant reliability impact to the system manifests itself during the next CSPP cycle, the NYISO will address the issue in the next Reliability Needs Assessment.
Ontario

Ontario was traditionally a winter peaking system. Since 1998 the system has been summer peaking in eleven of those thirteen years. The 2010 summer actual peak demand was 25,075 MW which was more than 1,500 MW higher than last year’s projection of 23,500 MW. The peak was driven by hotter than normal weather conditions. This year’s forecast projects summer peak demand to decline from 23,500 MW in 2011 to 22,150 MW in 2021. Likewise, overall energy demand is expected to average an annual growth rate of -0.1 percent over that time period.

Existing resources including demand response connected to the IESO-controlled grid is about 36,700 MW. The Certain capacity is almost 31,100 MW. About 1,300 MW of new generation was added since last year. Most of the new addition was from gas-fired generation (1,000 MW). Four coal units with an installed capacity of almost 2,000 MW were shut down in October of 2010. Two additional units at Nanticoke are expected to be shut down by the end of 2011. All coal-fired plants in the province will be phased out by 2014. The Ontario Power Authority (OPA) will negotiate a contract for biomass fuelled generation from Atikokan Generating Station. The conversion of two units at Thunder Bay Generating Station to run on natural gas will start over the period leading up to 2014. Pickering Nuclear Generating Station is scheduled for retirement, but the feasibility of extending the operating life of the Pickering generating units is being studied and the government expects to make a decision by 2012. Bruce and Darlington Nuclear Generating Stations will be refurbished in the latter half of the 10-year period. The conversion to natural gas of some (or all) remaining units at Lambton and Nanticoke will be considered under a range of different scenarios for nuclear generation and system peaking requirements. The Reserve Margins projected over the 10-years are all above the provincial target.

New series capacitors were installed in 2010 at Nobel Transmission Station (TS) on two 500 kV circuits to increase the transfer capability of the Flow-South Interface. A new 176 km (110 mile) 500 kV double circuit line from the Bruce Power complex to Milton Switching Station (SS) is being constructed with completion expected in 2012. This new line is required to accommodate the output of all eight generating units at the Bruce complex and the existing and future renewable generating capacity within the area.

The integration of variable wind and solar generation is an important challenge on which the IESO has been focusing, as the amount of renewable distributed and grid-connected generation grows in the province. There are a number of ongoing initiatives that will help ensure reliability going forward, namely centralized forecasting, visibility of distributed generators to the system operator and dispatchable capability of variable generators.
Demand
This year’s demand forecast net of conservation has an average annual growth rate of -0.55 percent over the period 2011-2021 compared to last year’s average growth of -0.30 percent for the years 2010-2019. The average growth rate is higher this year due to stronger demand growth driven by economic and demographic factors. However, demand growth continues to be negative as a result of Conservation efforts and growth in embedded (distributed) generation over this long-term assessment period.

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-intensive 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.

The Ontario Power Authority (OPA) and electricity distributors are responsible for delivering Conservation programs throughout the province. To date, there are a number of Conservation-related initiatives that will reduce electricity demand. These programs range from lighting and appliance replacement to building retrofits targeted towards the residential, commercial, and industrial sectors. Measurement and verification are the responsibility of the OPA as part of their mandate. Incremental Conservation savings are expected to reach 3,900 MW over the forecast horizon.

Demand Response within Ontario includes a number of different programs. Some wholesale customers in the province bid their load into the market and are responsive to price through IESO dispatch instructions. Other customers have been contracted by the OPA to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and currently amounts to slightly more than 1,500 MW in total, of which 48 percent is included for seasonal capacity planning purposes, with half of the included amount categorized as interruptible. This amount is expected to grow over time as more loads are contracted to respond to tight supply conditions. By the end of the forecast, the interruptible capacity component is expected to grow by nearly 800 MW—about half counted for seasonal capacity planning purposes. The impacts of these initiatives are reflected in the reliability analysis.
Ontario does not have renewable portfolio standards. However, there are a number of initiatives and programs that are expected to generate Conservation savings and demand response. This information is incorporated in the IESO’s reliability analysis.

The IESO quantifies the uncertainty in peak demand due to weather variation through the use of Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. This is used with Monthly Normal weather demand to conduct probabilistic analysis. As well, the IESO uses an Extreme Weather scenario to study the impacts of adverse weather conditions on reliability of the IESO-controlled grid.

**Generation**

As shown in Figure 11, Ontario's existing installed generation capacity represents nuclear (33%), oil/gas (27%), hydroelectric (23%), coal (13%), wind (3.7%), wood (biomass) and waste-fuelled (landfill gas) (0.3%) generation.

For summer 2011, the total Existing-Certain capacity resources connected to the IESO-controlled grid is 31,094 MW. Existing-Inoperable capacity amounts to 28 MW. Approximately 9,800 MW of Future-Planned and Conceptual renewable resources are expected to come on-line by 2018. This amount includes resources that are embedded and grid-connected. This is made up by more than 6,300 MW of wind, 2,200 MW of solar, 900 MW of hydroelectric and 400 MW of biomass.

![Figure 11 – Ontario Area Capacity Mix by Fuel Type for 2011](image-url)
As of spring 2011, the existing installed capacity of wind generation resources on the IESO-controlled grid is 1,334 MW. Thirteen percent of the installed wind capacity is assumed to be available at the time of summer peak, and thirty-two 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 40 percent of installed for the summer peak and no contribution for the winter peak. The values are based on historical modeled photovoltaic output data at the time of summer and winter peaks. No derated value is projected for biomass generation. It is assumed that the full installed capacity will be available at the time of the peak. The data below represents only Future-Planned and Future-Other resources, excluding any Conceptual projections.

Assumptions related to amounts and types of Future-Planned and Conceptual capacity resources are derived from the Ontario Power Authority. The OPA is the electricity system planner for the province of Ontario.

The OPA’s statutory objects include some of the following requirements: to ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity Conservation, demand management, renewable and other generation, and transmission over the long-term.

Generation resources identified for reliability analysis include:

- Those which are currently in operation;
- Those which are not currently in operation but are anticipated to enter service in the future as a result of an executed financial contract with the OPA or an existing or anticipated government directive; and
- Those Conceptual resources identified in longer-term power system planning scenarios developed by the Ontario Power Authority.

An adjustment or confidence factor was not applied to Conceptual resources for purposes of this assessment. Planning scenarios are developed by the OPA on an ongoing basis as part of its regular planning activities. Conceptual resource projections were reviewed
within the planning processes used in preparation for this assessment. Resources have been identified and categorized consistent with the planning assumptions of the OPA.

These planning assumptions reflect the anticipated take-up of renewable energy procurement initiatives administered by the OPA, sequencing of associated transmission developments, projections around nuclear refurbishments and other projections.

**Capacity Transactions on Peak**

No Firm, Expected or Provisional imports into Ontario or exports to other regions during on-peak periods are projected for this assessment period.

**Transmission**

Construction of a new 176 km (110 mile) 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) is in progress, with completion expected in 2012. This new line is required 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 1,250 MW of new renewable generating capacity that is forecasted for development within the area. With the new generating facilities, the combined generation in the Bruce area is projected to exceed 8,100 MW. The completion of the Bruce to Milton line has been delayed due to easement and right-of-way acquisition.

If the current schedule for the return to service of the two Bruce units is maintained, then the units will be in-service before the new 500 kV line. Although the installation of the new SVCs at Nanticoke and Detweiler will improve the transfer capability from the Bruce area there could be periods when the new generation will need to be constrained until the new line is completed.

The existing SPS will also 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 presently 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 become more critical. This SPS will be a permanent feature to deal with contingencies and is not intended to avoid or delay the construction of bulk transmission facilities. The new SPS is scheduled to be in service by late 2013.

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

Phase angle regulators (PARs) are installed on all four of the Ontario – Michigan interconnections. One PAR, on the Keith to Waterman 230 kV circuit J5D, has been in service and regulating since 1975. The other three available PARs, on the Lambton to St. Clair 230 kV (circuit L51D), the 345 kV circuit L4D and the Scott-Bunce Creek 230 kV (circuit B3N) remain idle. The operating agreements are ready. The completion of the filing process with FERC and the U.S. Department of Energy is in progress. Although they are currently bypassed, these PARs can be placed in service and operated to control flows during emergency conditions.

In October 2009, Ontario launched a feed-in tariff (FIT) program which generated strong interest in renewable generation. Proponents representing more than 17,000 MW of renewable generation have applied for connection under the FIT program as of May 2011. The existing transmission system has already accommodated over 3,500 MW of FIT contract offers. The contract offers include transmission and distribution-connected projects. The remaining projects are awaiting further assessments.

The Government of Ontario’s Long-Term Energy Plan, specifies five priority transmission projects to accommodate renewable generation, serve new load, and support reliability. Further in a Supply Mix Directive on February 17, 2011, the OPA was required to include the five priority projects in its Integrated Power System Plan (IPSP). The five priority transmission projects are:

- Device(s) to enhance transfer capability, such as series or static var compensation, or other similar devices, in Southwestern Ontario;
- Upgrade existing line(s) west of London;
- A new line west of London;
- Enhance the East-West Tie along the east shore of Lake Superior through a new line; and,
- New line to Pickle Lake.

**Québec**

The Total Internal Demand forecast for the 2011-2021 assessment period is slightly different last year’s 2010-2019 forecast. The compound average annual growth is about 0.89 percent over the assessment period. Capacity resources for the 2011/2012 winter season total 43,851 MW, of which 39,190 MW is categorized as Existing-Certain. A portion of installed wind capacity is under contract with Hydro-Québec Production (HQP) and is derated by 100 percent, as it has been in earlier assessments.

Other wind generation sites are under-contract with Hydro-Québec Distribution (HQD) with peak capacity amounting to approximately 30 percent of nameplate capacity. The
refurbishment of the Gentilly-2 nuclear generating station (675 MW) will span between 2012 and 2014 and is projected to return to service for the 2014/2015 winter season. The Tracy plant (450 MW) has been mothballed.

The most recent Québec Balancing Authority Area Interim Review of Resource Adequacy, which was approved by NPCC’s Reliability Coordinating Committee on November 30, 2010, indicated that the Reserve Margin for reliability criterion compliance (expressed as a percentage of the Total Load Forecast) should be approximately 10 and 12 percent for short- and long-term assessments, respectively. When compared to other NPCC sub-regions, the Reserve Margin for Québec is lower than other because hydro plants with multi-annual reservoirs have inherently higher availability. Accordingly, Québec’s Anticipated Capacity Resources Reserve Margin varies between 12.5 and 14.9 percent, remaining above the target Reserve Margin throughout the assessment period.

A total of 891 miles of planned transmission lines are expected to come into service between 2011 and 2021, with an additional 232 circuit miles currently under construction. There are no transmission reliability concerns identified for the Québec sub-region. 4,495 MW of additional capacity resources are also expected to come on line during the assessment period, including 2,666 MW of wind generation and 196 MW of biomass.

**Demand**

The 2011/12 winter peak Total Internal Demand forecast for Québec is 37,153 MW, increasing to 40,968 MW by 2021, with an average annual growth rate of 0.89 percent.

Hydro-Québec Distribution (HQD) is the only Load Serving Entity (LSE) in the Québec sub-region. Thus, the load forecast is conducted for the Québec Balancing Authority Area, represented as a single entity, negating any need for demand aggregation. Resource evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.

The load forecast was prepared using end-use models for different electricity consumption sectors, combined with data gathered through customer surveys, economic, demographics and technological assessments, as well as other factors that impact electricity use. Economic conditions are cautious as slow recovery continues with many industrial sector still experiencing difficulties.

The Québec peak load forecast is based on 36-year average temperatures (1971-2006), adjusted by 0.30°C (0.54°F) per decade starting in 1971 in order to reflect the impact of climate change in Québec. Each year of historical climatic data is adjusted ±3 days to gain information on conditions that occurred during either a weekend or a week day.
Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of the peak hour for each scenario.

Load forecasts have incorporated expected reductions in peak demand to be achieved by Hydro-Québec Energy Efficiency programs. HQD’s goal for recurring energy savings in 2012 is 8.8 TWh, increasing to 25.3 TWh in 2021. These projections will be achieved primarily through Energy Efficiency Plans (EEP) to reach 17 TWh by 2021. Existing Energy Efficiency trends in the demand forecast models (including programs that were originally, implemented by Hydro-Québec during the 1990s) will also contribute.

The EEP focuses on energy Conservation measures with programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. These programs encourage Conservation of Energy Star appliances, lightning and refrigerators, increased recycling activities, management of electric power for large industry, as well as programs catered toward industrial users. The projected impact of these programs is incorporated in the load forecast of this assessment.

In terms of capacity, the expected impact of these programs reduction of on-peak demand for 2011/12 is 1,530 MW, growing to approximately 3,650 MW in 2021/22.

There are no Renewable Portfolio Standards (RPS) in Québec; however, some Demand Side Management (DSM) targets have been proposed by the Québec Government. Accordingly, Hydro-Québec Distribution must to file monitoring reports to the Québec Energy Board in relation to these targets.

The Québec sub-region has two types of Demand Response Programs totaling 1,600 MW specifically designed for peak-shaving during winter operating periods:

- Interruptible demand programs (mainly addressed to large industrial customers) have an impact of 1,350 MW on-peak demand.
- A voltage reduction program with 250 MW of demand reduction at peak.

Current projections indicate that the total DSM will contribute slightly less in 2021.

**Generation**

As shown in Figure 12, Québec’s existing installed generation capacity 92% hydroelectric, 3% thermal, 3% wind, 2% nuclear, and less than 1% biomass generation. Most of Québec’s generating resources are hydro facilities. Some coal and gas generation is also used for peaking purposes, accounting for less than two percent of total capacity.
The Gentilly-2 nuclear plant (675 MW) announced refurbishment activities to commence in fall of 2012 and continue until 2014. Hydro-Québec is also adding renewable resources, including biomass, geothermal and solar energy. Finally, the next hydroelectric generation project, the Romaine Complex is expected to come online between 2014 and 2020 on the Lower North Shore of the St. Lawrence River. This project consists of four generating stations, totaling 1,550 MW.

Plans for additional resources over the assessment period are primarily renewables, including hydro, wind and biomass resources. Large hydro plants are presently under construction (Romaine Complex) and represent the most important part of the new effective capacity additions. Smaller hydro plants, as well as some biomass and wind resources are assessed based on contractual agreements between HQD and Independent Power Producers (IPP).

Wind capacity forecasts are modeled using long historical data series. Results of the study were presented to the Québec Energy Board and the NPCC. This study indicated that the actual wind plant capacity and contribution to Loss of Load Expectation was equal to 30 percent of nameplate capacity. This first effective wind capacity calculation was based on the expected geographic dispersion of 3,000 MW of wind plants.

Biomass resources currently amount to 164 MW of Existing-Certain capacity in 2011, with an additional 52 MW of on-peak capacity planned to come online by 2021.
Capacity Transactions on Peak

Expected capacity purchases are planned by Hydro-Québec Distribution for its own needs (Québec internal demand). These purchases will show up during peak periods only: for the 2011/12 peak period they will amount to about 100 MW. The long-term assessment shows a need for about 1,100 MW during peak periods. These purchases may be supplied by resources located in Québec or in neighboring markets. In this regard, HQD has designated 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, HQD proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

For the period from June through September 2011, there are firm capacity sales to New England, New York and Ontario totaling 1,661 MW. Moreover, during the same period there is an expected firm capacity sale of 421 MW to New York.

After 2011 and for the period of this assessment, the Québec sub-region will support firm capacity sales totaling 455 MW to New England and Ontario (Cornwall). These are backed by firm contracts for both generation and transmission. These firm capacity sales will continuously decline to 151 MW in 2021.

Finally, during summer periods from 2012 to 2021, there will be additional expected capacity sales of 1,574 MW in 2012, 1,521 MW in 2013 and 1,866 MW from 2014 to 2021.

Transmission

This section briefly describes the bulk power system transmission additions anticipated in-service during the 2011/2021 period.

Eastmain-1-A – La Sarcelle Hydro Project 268

Presently, the Eastmain-1-A (768 MW) and the La Sarcelle (150 MW) hydro generation stations are in the commissioning phase along with the accompanying transmission. TransÉnergie, the Transmission Planner, has commissioned the Eastmain-1-A – Eastmain-1 (1.0 km) double-circuit line and the LaSarcelle – Eastmain-1 (102.1 km) 315 kV single-circuit line in 2011. These lines complete the La Sarcelle – Eastmain-1 – Eastmain-1-A generation complex integration into the main grid at Némiscau T.S. (James Bay sub-system).

Romaine River Hydro Complex

Hydro-Québec Production (HQP) is now constructing the Romaine River Complex on the Lower North Shore of the St. Lawrence River. The Romaine River discharges into the St. Lawrence River near the town of Havre-Saint-Pierre. This generating complex is
made up of four generating stations totaling 1,550 MW. TransÉnergie is now in the planning stage for the integration of this project to the system.

The Generating Stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 (645 MW) and Romaine-1 (270 MW) will be integrated in 2014 - 2016 at Arnaud 735/315 kV substation. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017 - 2020 at Montagnais 735/315 kV substation. The Romaine Transmission Project has been filed with the Québec Energy Board on March 2, 2011 and subsequent hearings will be held. Main system upgrades for this project require construction in 2014 of a new 735 kV switching station to be named “Aux Outardes” and located between existing Micoua and Manicouagan T.S. Two 735 kV lines will be redirected into the new station and one new 735 kV line (5 km or 3 miles) will be built between Aux Outardes and Micoua.

Other work required on the main system is:
- New series compensation at Jacques-Cartier (Line 7018) and Duvernay (Line 7002) stations;
- Existing series compensation upgrades at Arnaud station;
- Capacitor bank additions at Saguenay 161 kV station;
- Two 735 kV, 330 MVAr shunt reactor additions (Laurentides, Appalaches);
- Line protection modifications at several 735 kV stations; and,
- Communications network extensions.

These main system upgrades are required to maintain conformance to Planning Standards with the new Romaine generation on the grid.

**Wind Integration Projects**
Different calls for tenders for wind generation have been issued by Hydro-Québec Distribution in the past years. A total of approximately 3,348 MW (Including wind generation already in service) is forecasted to be on line in 2015. A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages to integrate this wind generation.

These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspesia Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

All system additions and modifications have been filed with the Québec Energy Board on August 17, 2010. Hearings were held on this project and it was approved on December 23, 2010. These include transmission additions to be made on the main system, such as series compensation additions at Chénier (Line 7044), Grand-Brûlé (Line 7045) and Duvernay (Line 7016) 735 kV stations. The project also includes the addition of an SVC at Bout-de-l’Île substation after the addition of a 735 kV section at Bout-de-l’Île and an
SVC at Jacques-Cartier substation. Nominal current upgrades will also be done on existing series compensation at La Vérendrye, Abitibi and Duvernay. A thermal capacity upgrade will be done on the two Lévis – Nicolet 735 kV lines and several protection and communications modifications are also scheduled to finalize this project in 2016.

**System Reinforcement Project**
A System Reinforcement Project submitted to and approved by the Québec Energy Board du Québec is still ongoing. Mainly, this includes two Static Var Compensators (SVCs) to be installed at Chénier 735 kV substation and series compensation on two 735 kV lines (The two Chamouchouane – Jacques-Cartier lines). The two SVCs and series compensation are now under construction and will be commissioned for the 2011-2012 peak load period. Moreover, the Board has also approved the addition of two 200 MVAr inductive branches on the Chénier SVCs. This is to account for the filing of the 2 X 1,200 MW firm point to point transmission service by Hydro-Québec Production on the HQT-MASS and HQT-NE interconnections using the Châteauguay and Phase II interconnections. The project also includes Bergeronnes series compensation nominal current-carrying capacity upgrade in 2014. Finally, a third 345 MVAr 315 kV shunt capacitor bank is now under construction at Duvernay substation and will be in service by the end of 2011.

**Chamouchouane – Montréal 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 to Montréal (about 370 km or 230 miles) is required around 2017. This optimization will result in regrouping some of the abovementioned 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 Interface, thus optimizing operations flexibility.

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

**Regional Projects**
In 2013, the 735 kV section addition at Bout-de-l’Île (East end of Montréal Island) substation also includes the addition of two 735/315 kV, 1,650 MVA transformers. The new 735-kV source will permit redistribution of load around the Greater Montréal area and will absorb load growth in the eastern part of Montréal. This project will enable major modifications to the Montréal area regional sub-system.
Many of the present 120 kV distribution stations will be rebuilt into 315 kV stations and the regional network will be converted to 315 kV (Vimont, Bélanger, Blainville, Fleury, de Lorimier substations).

Other regional projects will continue in the Québec City area (Limoilou, Lefrançois and Charlesbourg projects), in the Beauceville area, and in the Mauricie – Montréal 315 kV corridor (Pierre-Le Gardeur 315/120 kV, Lachenaie and Lanaudière projects).
Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) as shown in Figure 7 was assumed. The assumptions are summarized in Table 4 and Figure 13.

| Table 4 |
|PJM, RFC-Other and MRO-US 2012 Assumptions^{22}|
|---|---|---|
PJM RFC-Other MRO-US |
|Peak Load (MW) 164,322 94,045 35,760 |
|Peak Month July July July |
|Assumed Capacity (MW) 187,499 101,528 39,663 |
|Purchase/Sale (MW) -802 0 0 |
|Reserve (%) 14 8 11 |
|Operating Reserves (MW) 3,400 2,206 1,700 |
|Curtailable Load (MW) 3,743 2,000 1,666 |
|No 30-min Reserves (MW) 2,765 1,470 1,200 |
|Voltage Reduction (MW) 2,201 0 1,100 |
|No 10-min Reserves (MW) 635 736 500 |
|Appeals (MW) 400 0 200 |
|Load Forecast Uncertainty 93.54 +/- 5.55, 11.11, 16.66 94.62 +/- 4.63, 9.26, 13.88 92.79 +/- 6.20, 12.39, 18.59 |

^{22} 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/](http://www.nerc.com/~esd/)
ReliabilityFirst
ReliabilityFirst is a newly formed not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst 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.

ReliabilityFirst 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 was a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities were identified and transferred to ReliabilityFirst.

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 2010 RRS Report).

**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 2010 RRS Report).

**PJM-RTO**
**Load Model**
The forecast contained in the January 2011 PJM Load Forecast was used, consistent with the 2011 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.) 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 2011, 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.

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**Expected Resources**
All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Active generation projects in the PJM interconnection queues were modeled in the PJM-RTO study area after applying a suitable commercial probability.

**Expected Transmission Projects**
The transfer values shown in the study are reflective of peak load flow model conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM’s Regional Transmission Expansion Plan (RTEP).²⁵

**Market programs**
The Reliability Pricing Model (RPM)²⁶ is PJM’s capacity-market model. Implemented in 2007, the RPM, based on making capacity commitments three years ahead, is designed to create long-term price signals to attract needed investments in reliability in the PJM region.

The long-term RPM approach, in contrast to PJM’s previous short-term capacity market, includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response and transmission facilities.

The RPM model works in conjunction with PJM’s Regional Transmission Expansion Planning (RTEP) process to ensure the reliability of the PJM region for future years.

The RPM includes the continued use of self-supply and bilateral contracts by load-serving entities (LSEs) to meet their capacity obligations. The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through contracts.

The RPM provides:
- Procurement of capacity three years before it is needed through a competitive auction;
- Locational pricing for capacity that reflects limitations on the transmission system’s ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;

²⁵ See: [http://pjm.com/planning.aspx](http://pjm.com/planning.aspx)
The technical modeling requirements for the PJM Reliability Pricing Model are consistent with the existing modeling and methods used at PJM, per the above modeling summaries used in this study.

**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 2011 reserve requirement study.

**Fuel**

Figure 14 shows PJM-RTO’s resource capacity mix by fuel type for the summer of 2011 on an installed capacity basis, representing 49% fossil; 14.6% combustion turbine; 18.1% nuclear; 13.1% combined cycle; 4.2% hydroelectric; 0.3% diesel, and 0.3% wind generation.

![PJM Capacity Mix by Fuel Type - 2011](image)

*Figure 14 – PJM-RTO Capacity Mix by Fuel Type for 2011*
RESULTS

The objective of this study was to evaluate, on a consistent basis through a multi-area probabilistic assessment, the long range adequacy of the NPCC Areas’ and neighboring Regions’ plans to meet their Loss-of-Load Expectation (LOLE) planning criteria. Three reliability indices were computed for this evaluation.

The first index computed was the daily LOLE (days/year) resource adequacy design criteria for the NPCC areas. The other two indices are those specified in the GTRPMTF Final Report on Methodology and Metrics. The first of these is the annual Loss-of-Load Hours (LOLH), sometimes referred to as the hourly LOLE, in hours/year. The LOLH is the expected number of hours per year during which the system of interest does not have sufficient resources available to meet its firm load demand.

The second of the metrics from the GTRPMTF is the Expected Unserved Energy (EUE), sometimes referred to as the Loss-of-Energy Expectation (LOEE), in MWh/year. This is computed by accumulating the amount of shortage, in MW, for each hour for which the system of interest does not have sufficient resources available to meet its firm load demand. To account for variations in system size and energy demand, the EUE is often normalized in terms of the total Net Energy for Load (normalized EUE), and is expressed in MWh of EUE per million MWh of load.

The figures on the following pages present the calculated indices for each of the NPCC Areas for the five years of the study period (2012 through 2016) and for each of the neighboring regions.
Figures 15(a) and 15(b) show the estimated annual Loss-of-Load Expectation (daily LOLE in days/year) for the NPCC Areas for the 2012-2016 study period.

**Figure 15(a) - Estimated Annual LOLE for NPCC Areas**

**Figure 15(b) - Estimated Annual LOLE for NPCC Areas**
Figures 15(c) and 15(d) show the estimated annual Loss-of-Load Expectation (LOLE) for the NPCC Areas and Neighboring Regions for the 2012-2016 study period.

**Figure 15(c) - Estimated Annual LOLE for NPCC Areas and Neighboring Regions**

**Figure 15(d) – Estimated Annual LOLE for NPCC Areas and Neighboring Regions**
Figures 16(a) and 16(b) show the estimated annual Loss-of-Load Expectation (LOLH in hours/year) for the NPCC Area for the 2012-2016 study period.

Figure 16(a) - Estimated Annual LOLH for NPCC Areas

Figure 16(b) - Estimated Annual LOLH for NPCC Areas
Figures 16(c) and 16(d) show the estimated annual Loss of Load Expectation (LOLH) for the NPCC Areas and Neighboring Regions for the 2012-2016 study period.
Figures 17(a) and 17(b) show the estimated annual normalized Expected Unserved Energy (EUE) for the NPCC Areas for the 2012-2016 study period.
Figures 17(c) and 17(d) show the estimated annual normalized Expected Unserved Energy (EUE) for the NPCC Areas and the Neighboring Regions for 2012-2016.
Table 5 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the *NERC 2011 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 1.0% lower than the corresponding sum of the NPCC Areas annual energy forecasts.
### Table 5 – Comparison of Energies Modeled

<table>
<thead>
<tr>
<th>Year</th>
<th>2012</th>
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OBSERVATIONS

Figures 18(a) and 18(b) summarize the estimated annual NPCC Area Loss-of-Load Expectation (LOLE) from the NPCC Summer Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

**Figure 18(a)** - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)

**Figure 18(b)** - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)
This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 19(a) and 19(b) add the estimated annual NPCC Area Loss of Load Expectation (LOLE) for 2011 – 2016 from the Long Range Adequacy Overviews.
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 2011 -2016 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 2011 - 2012 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 2011 summer and November 2011 to March 2012 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 (2011 -2012) 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 - 2016 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 (2011 – 2016) 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, 2011.

A report of the results of the winter assessment will be published no later than June 30, 2011.

A report summarizing the results of the long-range overview will be published no later than December 31, 2011.
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</table>

* 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