Northeast Power Coordinating Council
Reliability Assessment
For
Winter 2015-16

FINAL REPORT
Approved by the RCC
December 1, 2015

Conducted by the
NPCC CO-12 & CP-8 Working Groups
# TABLE OF CONTENTS

1. **EXECUTIVE SUMMARY** ........................................................................................................ 1
   
   SUMMARY OF FINDINGS ........................................................................................................ 1

2. **INTRODUCTION** ................................................................................................................... 5

3. **DEMAND FORECASTS FOR WINTER 2015-16** ..................................................................... 6
   
   SUMMARY OF RELIABILITY COORDINATOR AREA FORECASTS ............................................... 7

4. **RESOURCE ADEQUACY** ....................................................................................................... 12
   
   NPCC SUMMARY FOR WINTER 2015-16 ................................................................................ 12
   MARITIMES .......................................................................................................................... 14
   NEW ENGLAND .................................................................................................................. 15
   NEW YORK ....................................................................................................................... 17
   ONTARIO .......................................................................................................................... 18
   QUÉBEC ........................................................................................................................... 19
   PROJECTED CAPACITY ANALYSIS BY RELIABILITY COORDINATOR AREA ............................... 21
   GENERATION RESOURCE CHANGES .................................................................................. 22
   FUEL INFRASTRUCTURE BY RELIABILITY COORDINATOR AREA ......................................... 27
   WIND CAPACITY ANALYSIS BY RELIABILITY COORDINATOR AREA ..................................... 29

5. **TRANSMISSION ADEQUACY** ............................................................................................ 36
   
   INTER-REGIONAL TRANSMISSION ADEQUACY ................................................................... 38
   AREA TRANSMISSION ADEQUACY ASSESSMENT .................................................................. 40
   AREA TRANSMISSION OUTAGE ASSESSMENT ....................................................................... 43

6. **OPERATIONAL READINESS FOR WINTER 2015-16** ....................................................... 45
   
   MARITIMES .......................................................................................................................... 45
   NEW ENGLAND .................................................................................................................. 46
   NEW YORK ....................................................................................................................... 48
   ONTARIO .......................................................................................................................... 50
   QUÉBEC ........................................................................................................................... 51

7. **POST-SEASONAL ASSESSMENT AND HISTORICAL REVIEW** ........................................ 53
   
   WINTER 2014-15 POST-SEASONAL ASSESSMENT ................................................................ 53

8. **2015-16 WINTER RELIABILITY ASSESSMENTS OF ADJACENT REGIONS** .................... 56

9. **CP-8 2015-16 WINTER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT** ..... 57
   
   EXECUTIVE SUMMARY ....................................................................................................... 57

APPENDIX I – **WINTER 2015-16 NORMAL LOAD AND CAPACITY FORECASTS** ...................... 58
   
   TABLE AP-1 - NPCC SUMMARY ........................................................................................... 58
   TABLE AP-2 – MARITIMES ..................................................................................................... 59
   TABLE AP-3 – NEW ENGLAND .............................................................................................. 60
   TABLE AP-4 – NEW YORK ..................................................................................................... 61
The information in this report is provided by the CO-12 Operations Planning Working Group of the NPCC Task Force on Coordination of Operation. Additional information provided by Reliability Councils adjacent to NPCC.

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- Frank Peng | Independent Electricity System Operator
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- Paul Kure | Reliability First (RFC)
1. **Executive Summary**

This report is based on the work of the NPCC CO-12 Seasonal Assessment Working Group and focuses on the assessment of reliability within NPCC for the 2015-16 winter operating period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the winter 2014-15. Moreover, the NPCC CP-8 Working Group provides a seasonal multi-area probabilistic reliability assessment. Results of this assessment are included as a chapter in this report and supporting documentation is provided in Appendix VIII.

Those aspects that the CO-12 Working Group has examined to determine the reliability and adequacy of NPCC for the season are discussed in detail in the specific report sections. The following **Summary of Findings** addresses the significant points of the report discussion. These findings are based on projections of electric demand requirements, available resources and transmission configurations. This report evaluates NPCC’s and the associated Balancing Authority areas’ ability to deal with the differing resource and transmission configurations within NPCC and the associated Balancing Authority areas’ preparations to deal with the possible uncertainties identified in this report.

**Summary of Findings**

- The NPCC forecasted coincident peak demand of 110,127 MW is anticipated to occur week beginning January 17, 2016, which is 615 MW (0.1 percent) less than the forecasted 2014-15 coincident peak of 110,742 MW. The capacity outlook indicates a forecasted coincident peak Net Margin of 18,595 MW (16.9 percent) in terms of the 110,127 MW forecasted peak demand. The NPCC 2014-15 coincident winter peak demand of 108,092 MW occurred on January 8, 2015 at HE18 EST.

- The minimum percentage of forecasted Net Margin available to NPCC is 16.9 percent, week beginning January 17 2016 and the maximum forecasted NPCC Net Margin of 34.4 percent occurs during the week beginning March 20, 2016.

- During the NPCC forecasted peak demand, the forecasted Area Net Margin in terms of normal forecasted demand ranges from approximately 5.6 percent in Québec to 29.6 percent in New York.

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1 The published NPCC Assessments can be downloaded from the NPCC website [https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx](https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx)

2 Load and Capacity Forecast Summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I
• When comparing the previous winter peak demand (January 08, 2015) to this winter’s expected peak week (January 17, 2016), the NPCC installed capacity has increased by 3,327 MW. Individual area changes are the following: Maritimes, +202; New England, +429 MW; New York, +349 MW; Ontario, +1,648 MW; and Québec, +699 MW.

• When comparing the previous winter assessment to the 2015-16 winter assessment, the NPCC operable capacity has decreased by 1,448 MW. This is largely attributed to the increase in Known Maintenance/Derates, Unplanned Outage assumptions and Operating Reserve Margins. Additional details are provided in Section 4 of this report.

• No delays are forecasted for the commissioning of new resources. However, any delay should not materially impact the overall net margin projections for NPCC.

• The Maritimes Area has forecasted a winter 2015-16 normal peak demand of 5,509 MW for the week beginning January 24, 2016 with a projected net margin of 392 MW (7.1 percent). This winter peak demand forecast is 111 MW (2.0 percent) more than the winter peak demand forecast of 2014-15 and is 195 MW (3.7 percent) higher than the actual peak of 5,314 MW for winter 2014-15. The increase in the forecasted peak demand from the 2014-15 forecast is expected to occur during the historical peaking period between late January and mid-February and attributed to a slight increase in customer load growth.

• New England is forecasting adequate resources to meet the normal peak demand for the 2015-16 winter season. A normal peak demand of 21,077 MW is forecast for the week beginning January 10, 2016, with a projected net margin of 3,450 MW (16.4 percent). This winter peak demand forecast is 9 MW (0.04 percent) less than the winter peak demand forecast for 2014-15. The lack of load growth is largely attributed to the passive demand resources procured by the region’s Forward Capacity Market (FCM), an updated economic forecast, and historical load and weather inputs. Short-term capacity and energy purchases from neighboring systems, anticipated to help serve the electrical demands on the system, are not included in the provided margins. New England continues to monitor factors affecting natural gas deliverability throughout the winter reliability assessment and recognizes this as natural gas-at-risk. For the winter period, approximately 4,200 MW of natural-gas-fired capacity may be at risk due to constrained natural gas pipelines and the deliverability risk is continuously evaluated throughout the outage coordination process into real time operations. The 2014-15 Winter Reliability Program (WRP) proved to be a success, and ISO-NE fully expects that the FERC approved 2015–16 Winter Reliability Program will continue to address several challenges that could have an adverse impacts on generation during the 2015–16 winter period. Key components of the program will create incentives for generators to have
sufficient fuel oil supplies on site and natural-gas-fired generators to procure adequate liquefied natural gas (LNG). The program also will support dual-fuel generator commissioning and testing and includes an improved demand-response program.

- The NYISO anticipates adequate resources to meet demand for the 2015-16 winter season. A capacity margin of 7,253 MW (29.6 percent) is expected for the normal demand forecast of 24,515 MW, which was updated in December, 2014. It is lower than the previous year’s forecast of 24,737 MW by 222 MW (0.90 percent) and 133 MW (0.54 percent) less than the actual winter peak of 24,648 MW in winter 2014-15. Construction of the Transmission Owners Transmission Solutions (TOTS) began in fall 2015 and consists of three distinct transmission projects to increase transfer capability into Southeast New York. Reliable system operations will be maintained through careful coordination of outages to key elements of the 345 kV system.

- The IESO anticipates adequate resources to meet demand for the winter 2015-16 period. The forecasted Ontario winter peak is 22,389 MW for week beginning January 3, 2016 with a corresponding net margin of 3,705 MW (or 16.6 percent). For the winter period, the forecasted minimum net margin is 3,238 MW (or 15.6 percent) for the week beginning November 29th. Ontario’s 2014-15 winter peak demand was 21,814 MW, which was slightly lower than the peak forecast. This was mostly due to the continued decrease in wholesale customers’ consumption. However, a stronger U.S. economy combined with a lower Canadian dollar is expected to push demand growth in Ontario higher in 2016 due to an expected increase in manufacturing.

- The Québec area anticipated adequate resources to meet demand for the winter 2015-16 season. The current 2015-16 normal peak forecast is 38,192 MW (207 MW higher than the demand forecast presented in the prior winter assessment) and the forecasted operating margin is 2,126 MW (5.6 percent) for the peak operating week. This increase in demand is mainly attributed to the residential sector and specifically to higher peak demand for heating space use. An extreme forecast has also been evaluated and the projected margin is 1,116 MW. Compared to winter 2014-15, net installed capacity will have grown by 699 MW by December 2015. For the upcoming peak period, the first of two generators of La Romaine-1 (135/270 MW) generating station will be integrated at the La Romaine-2 315-kV substation with a 28 km (16 miles) line initially operated at 315 kV. New wind resources of 373 MW (net) will be in service (with a contribution at peak estimated at 112 MW). If peak demands are higher than expected, a number of measures are available to the System Control personnel.

The results of the CO-12 and CP-8 Working Groups’ studies indicate that NPCC and the associated Balancing Authority Areas have adequate generation and transmission for the Winter Operating Period and have developed the necessary strategies and
procedures to deal with operational problems and emergencies as they may develop. However, the resource and transmission assessments in this report are mere snapshots in time and base case studies. Continued vigilance is required to monitor changes to any of the assumptions that can alter this report’s findings.
2. **Introduction**

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 Working Group to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September) and the Winter Operating Period (defined as the months of December through March). The Working Group may occasionally study other conditions as requested by the TFCO.

For the 2015-16 winter operating period\(^3\) the CO-12 Working Group:

- Examined historical winter operating experiences and assessed their applicability for this period.
- Examined the existing emergency operating procedures available within NPCC and reviewed recent operating procedure additions and revisions.
- Reviewed the probabilistic assessment completed by the NPCC CP-8 Working Group, reflecting the implementation of operating procedures for the 2015-16 winter operating period. The results and conclusions of the CP-8 assessment are included as chapter 9 in this report and the full report is included as Appendix VIII.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator Area basis. These sensitivities included temperature variations, new wind generation, delays to in-service of new generation, load forecast uncertainties, evolving load response measures, fuel availability, system voltage and reactive capability.
- Reviewed the capacity margins for both normal and extreme forecasts while accounting for bottled capacity within the NPCC.
- Reviewed inter-Area and intra-Area transmission adequacy, including new transmission projects, upgrades or derates and potential transmission problems.
- Reviewed the operational readiness of the NPCC region and actions to mitigate potential problems.
- Coordinated data and modeling assumptions with NPCC CP-8 Working Group, and documented the methodology of each Reliability Coordinator area in its projection of load forecasts.
- Coordinated with other parallel seasonal operational assessments including the NERC Reliability Assessment Subcommittee (RAS) Seasonal Assessments.

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\(3\) For the purpose of this report, the Winter Operating Period is defined as the week beginning November 22, 2015 to the week beginning March 27, 2016 inclusive.
3. **Demand Forecasts for Winter 2015-16**

The non-coincident forecasted peak demand for NPCC over the 2015-16 winter operating period is 111,682 MW. This peak demand translates to a coincident peak demand of 110,127 MW which is expected during the week beginning January 17, 2016. The NPCC 2014-15 coincident peak demand of 108,092 MW occurred on January 8, 2015 at HE18 EST. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

Ambient temperatures and persistent winter conditions are important variables impacting the demand forecasts. However, unlike the summer demand forecasts, the non-coincident winter peak demand varies only slightly from the coincident peak forecast. This is mainly due to the drivers that impact the peak demand are concentrated into a specific period in time. In winter, the peak demands are determined mainly by low temperatures along with the reduced hours of daylight that occurs over the first few weeks of January. While the peak demands appear to be confined to a few weeks in January, each Area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and forecasted conditions.

In the operational planning time-frame, the impact of ambient weather conditions on load forecasts can be demonstrated by various means. The Maritimes and IESO represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. ISO-NE relates air temperature to the load response and increases the load by a MW factor for each degree below the base value. The NYISO uses a weather index that relates air temperature and wind speed to the load response and increases the load by a MW factor for each degree below the base value. TransÉnergie, the Québec system operator, updates forecasts on an hourly basis within a 12 day horizon based on information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area.

The method each Reliability Coordinator area uses to determine the peak forecast demand and the associated load forecast uncertainty relating to weather variables is described in Appendix IV. Below is a summary of all Reliability Coordinator Area forecasts.
Summary of Reliability Coordinator Area Forecasts

Maritimes

Winter 2015-16 Forecasted Peak: 5,509 MW (normal) and 5,913 MW (extreme), week beginning January 24, 2016


Winter 2014-15 Actual Peak: 5,314 MW on February 24, 2015 at HE7 EST

Figure 1: Maritimes Winter 2015-16 Weekly Demand Profile
New England

Winter 2015-16 Forecasted Peak: 21,077 MW (normal) and 21,737 MW (extreme), week beginning January 10, 2016

Winter 2014-15 Actual Peak: 20,583 MW, on January 8, 2015 at HE18 EST

Figure 2: New England Winter 2015-16 Weekly Demand Profile
New York

Winter 2015-16 Forecasted Peak: 24,515 MW (normal) and 26,079 MW (extreme) during the months of December, 2015 through February, 2016

Winter 2014-15 Forecasted Peak: 24,737 MW (normal) and 26,333 MW (extreme) during the months of December, 2014 through February, 2015


Figure 3: New York Winter 2015-16 Weekly Demand Profile
Ontario


Winter 2014-15 Forecasted Peak: 22,149 MW (normal) and 23,077 MW (extreme), week of January 4, 2015

Winter 2014-15 Actual Peak: 21,814 MW, on January 7, 2015 at HE18 EST

Figure 4: Ontario Winter 2015-16 Weekly Demand Profile
Québec

Winter 2015-16 Forecasted Peak: 38,192 MW (normal) and 39,202 MW (extreme) week of January 17, 2016

Winter 2014-15 Forecasted Peak: 37,985 MW (normal) and 38,754 MW (extreme) week of January 18, 2015

Winter 2014-15 Actual Peak: 38,950 MW, on January 8, 2015 at 7h21 EST.

**Figure 5: Québec Winter 2015-16 Weekly Demand Profile**
4. **Resource Adequacy**

**NPCC Summary for Winter 2015-16**

The assessment of resource adequacy indicates the week with the highest forecasted coincident NPCC demand is the week beginning January 17, 2016 (110,127 MW). Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

In Appendix I, Table AP-1 is the NPCC load and capacity summary for the 2015-16 Winter Operating Period. Appendix I, Tables AP-2 through AP-6, contain the load and capacity summary for each NPCC Reliability Coordinator area. Each entry in Table AP-1 is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator Areas.

Table 1.1 (below) summarizes the NPCC forecasted load and resource adequacy for the peak week January 17, 2016 compared to the winter 2014-15 forecasted peak week (week beginning January 18, 2015).

<table>
<thead>
<tr>
<th>All values in MW</th>
<th>2015-16 Forecast</th>
<th>2014-15 Forecast</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>163,628</td>
<td>160,301</td>
<td>3,327</td>
</tr>
<tr>
<td>*Net Interchange with areas outside NPCC</td>
<td>820</td>
<td>2,019</td>
<td>-1,199</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>164,448</strong></td>
<td><strong>162,320</strong></td>
<td><strong>2,128</strong></td>
</tr>
<tr>
<td>Demand (-)</td>
<td>110,127</td>
<td>110,742</td>
<td>-615</td>
</tr>
<tr>
<td>Interruptible load (+)</td>
<td>4,412</td>
<td>4,230</td>
<td>182</td>
</tr>
<tr>
<td>Known Maintenance/De-rate (-)</td>
<td>16,660</td>
<td>14,713</td>
<td>1,947</td>
</tr>
<tr>
<td>Required Reserve (-)</td>
<td>8,852</td>
<td>7,925</td>
<td>927</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>14,592</td>
<td>13,127</td>
<td>1,465</td>
</tr>
<tr>
<td><strong>Net Margin</strong></td>
<td><strong>18,595</strong></td>
<td><strong>20,043</strong></td>
<td><strong>-1,448</strong></td>
</tr>
<tr>
<td>Bottled Capacity (QC/Maritimes) to NPCC (-)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Revised Net Margin</strong></td>
<td><strong>18,595</strong></td>
<td><strong>20,043</strong></td>
<td><strong>-1,448</strong></td>
</tr>
<tr>
<td>Week Beginning</td>
<td>17-Jan-16</td>
<td>18-Jan-15</td>
<td>-</td>
</tr>
</tbody>
</table>

*Note: Net Interchange value offered as the summation of capacity backed imports and exports for the NPCC region.*

The Revised Net Margin for the 2015-16 winter capacity period has decreased by 1,448 MW from the previous winter. This reduction is largely attributed to the 1,947 MW increase in Maintenance/Derate and increased Unplanned Outage assumptions made predominantly in New York. During previous winters, New York has observed an
increase in performance derates for generators that are fueled by natural gas and oil and therefore the Unplanned Outage value is higher for 2015-16 in comparison to last winter.

The NPCC forecasted capacity outlook indicates a coincident peak Net Margin of 18,595 MW (16.9 percent) in terms of the 110,127 MW forecasted normal peak demand. If the NPCC area was to consider extreme peak demand, the forecasted extreme Net Margin would be 14,440 MW (12.6 percent) and is conveyed in Table 1.2.

Table 2.2: NPCC Normal and Extreme Margins for Winter 2015-16

The following sections detail the 2015-16 winter capacity analysis for each Reliability Coordinator area.
Maritimes

The Maritimes Area declared installed capacity is scheduled to be operational for the winter period; the net margins calculated include impacting factors such as wind, ambient temperature, and hydro flows that may derate generation and reflect expected out-of-service units. Imports into the Maritimes Area are not included unless they have been confirmed as released capacity from their source. Therefore, unless forced generator outages were to occur, there would not be any further reduction in the net installed capacity. As part of the winter planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions. Table 1.3 conveys the Maritimes anticipated operable capacity margins for the normal and extreme load forecasts of the winter assessment period.

<table>
<thead>
<tr>
<th></th>
<th>Winter 2015-16</th>
<th>Normal Forecast</th>
<th>Extreme Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>7,788</td>
<td>7,788</td>
<td></td>
</tr>
<tr>
<td>Net Interchange</td>
<td>-200</td>
<td>-200</td>
<td></td>
</tr>
<tr>
<td>Total Capacity</td>
<td>7,588</td>
<td>7,588</td>
<td></td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>256</td>
<td>256</td>
<td></td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>971</td>
<td>971</td>
<td></td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>693</td>
<td>693</td>
<td></td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>279</td>
<td>279</td>
<td></td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>5,509</td>
<td>5,913</td>
<td></td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
<td></td>
<td>392</td>
<td>-12</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td></td>
<td>7.1%</td>
<td>-0.2%</td>
</tr>
</tbody>
</table>

If the Maritimes real-time peak demand becomes higher than forecasted, the System Operator may implement operating procedures to maintain system reliability; as outlined in the Maritimes section of Operational Readiness for winter 2015-16.
New England

To determine the region’s capacity risks, ISO-NE assesses the difference between New England’s installed capacity and operable capacity under normal load forecasts. Some of these risks are threats to fuel deliverability for natural-gas-fired generation and the difference between a generator’s seasonal claimed capability (SCC) value and its capacity supply obligation (CSO). The SCC is recognized as a generator’s maximum output established through seasonal audits, whereas its CSO is its obligation to satisfy New England’s Installed Capacity Requirement (ICR) through a Forward Capacity Auction (FCA). Table 1.4 shows the variation in operable capacity margins for January 2016 recognizing these factors.

Table 1.4: New England Installed and Operable Capacity for Normal Forecast

<table>
<thead>
<tr>
<th>Normal Forecast</th>
<th>Jan - 2016</th>
<th>Jan - 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity + Noncommercial Capacity</td>
<td>29,932</td>
<td>32,872</td>
</tr>
<tr>
<td>Net Interchange</td>
<td>1,226</td>
<td>1,226</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>31,158</td>
<td>34,098</td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>21,077</td>
<td>21,077</td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>587</td>
<td>587</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>687</td>
<td>763</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>2,375</td>
<td>2,375</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>6,628</td>
<td>7,054</td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
<td>978</td>
<td>3,450</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td>4.6%</td>
<td>16.4%</td>
</tr>
</tbody>
</table>
ISO-NE also compares the installed capacity with operable capacity under extreme load forecasts to further determine New England’s capacity risks. This broadened approach helps identify potential capacity concerns for the upcoming capacity period and prepare for severe demand conditions. This analysis, shown in Table 1.5 for January 2016, shows the further reduction in the operable capacity margin recognizing these factors. If forecasted extreme winter conditions materialize and generators do not achieve their SCC, New England may need to rely more heavily on import capabilities from neighboring areas, as well as implement emergency operating procedures to maintain system reliability.

Table 1.5: New England Installed and Operable Capacity for Extreme Forecast

<table>
<thead>
<tr>
<th>Extreme Forecast</th>
<th>Jan - 2016</th>
<th>Jan - 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSO</td>
<td>29,932</td>
<td>32,872</td>
</tr>
<tr>
<td>SCC</td>
<td>31,158</td>
<td>34,098</td>
</tr>
<tr>
<td>Installed Capacity + Noncommercial Capacity</td>
<td>21,737</td>
<td>21,737</td>
</tr>
<tr>
<td>Net Interchange</td>
<td>587</td>
<td>587</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>687</td>
<td>763</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>2,375</td>
<td>2,375</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>7,334</td>
<td>7,804</td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
<td>-388</td>
<td>2,006</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td>-1.8%</td>
<td>9.2%</td>
</tr>
</tbody>
</table>
New York

New York determines its operating margin by comparing the normal seasonal peak forecast with the projected Installed Capacity adjusted for seasonal operating factors. Installed Capacity is based on seasonal Dependable Maximum Net Capability (DMNC), tested seasonally, for all traditional thermal and large hydro generators. Wind generators are counted at nameplate for Installed Capacity and seasonal derates are applied. Net Interchange is based on capacity transactions external to the New York Control Area (NYCA). Interruptible Load includes Emergency Demand Response Programs (EDRP) and Special Case Resources (SCR). Known Maintenance and Derates includes generator maintenance outages known at the time of this writing and derates for renewable resources such as wind, hydro and biogas based on historical performance data. The NPCC Operating Reserve Requirement for New York is one-and-a-half times the largest single generating source contingency in the NYCA. Beginning November 2015, the NYISO will start procuring operating reserve of two times (2,620MW) the largest single generating source contingency to ensure compliance with a New York State Reliability Council Rule.

Unplanned Outages are based on expected availability of all generators in the NYCA based on historic availability plus an additional 1,310 MW representing the potential loss of the largest single source generating contingency. Historic availability factors in all forced outages including those due to weather and availability of fuel. Table 1.6 presents a conservative scenario where the normal operating margin is 29.6 percent.

Table 1.6: New York Operable Capacity Forecast

<table>
<thead>
<tr>
<th>Winter 2015-16</th>
<th>Normal Forecast (MW)</th>
<th>Extreme Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>41,312</td>
<td>41,312</td>
</tr>
<tr>
<td>Net Interchange</td>
<td>338</td>
<td>338</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>41,650</td>
<td>41,650</td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>963</td>
<td>963</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>3,976</td>
<td>3,976</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>2,620</td>
<td>2,620</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>4,324</td>
<td>4,324</td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>24,515</td>
<td>26,097</td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
<td>7,253</td>
<td>5,671</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td>29.6%</td>
<td>21.7%</td>
</tr>
</tbody>
</table>
Ontario

Looking at the 2015-16 winter assessment period, considering existing and planned capacity coming in-service, the Ontario reserve requirement is met under both normal and extreme weather conditions, as indicated in Table 1.7.1.

Table 1.7.1: Ontario Operable Capacity Forecast

<table>
<thead>
<tr>
<th>Winter 2015-16</th>
<th>Normal Forecast (MW)</th>
<th>Extreme Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>36,276</td>
<td>36,276</td>
</tr>
<tr>
<td>Net Interchange</td>
<td>-500</td>
<td>-500</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>35,776</td>
<td>35,776</td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>555</td>
<td>555</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>7,075</td>
<td>7,075</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>1,664</td>
<td>1,664</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>1,498</td>
<td>1,498</td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>22,389</td>
<td>23,181</td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
<td>3,705</td>
<td>2,913</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td>16.6%</td>
<td>12.6%</td>
</tr>
</tbody>
</table>

The forecast energy production capability of the Ontario generators is calculated on a month-by-month basis. Monthly energy production capabilities for the Ontario generators are provided by market participants or calculated by the IESO. They account for fuel supply limitations, scheduled and forced outages and deratings, environmental and regulatory restrictions.

The results in Table 1.7.2 indicate that occurrences of unserved energy are not expected over the winter 2015-16 period. Based on these results it is anticipated that Ontario will be energy adequate for the normal weather scenario for the review period.
Table 1.7.2: Ontario Energy Production Capability Forecast by Month

<table>
<thead>
<tr>
<th>Month</th>
<th>Forecast Energy Production Capability (GWh)</th>
<th>Forecast Energy Demand (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nov 2015</td>
<td>16,506</td>
<td>11,595</td>
</tr>
<tr>
<td>Dec 2015</td>
<td>18,480</td>
<td>12,717</td>
</tr>
<tr>
<td>Jan 2016</td>
<td>18,768</td>
<td>13,134</td>
</tr>
<tr>
<td>Feb 2016</td>
<td>17,984</td>
<td>11,905</td>
</tr>
<tr>
<td>Mar 2016</td>
<td>18,167</td>
<td>11,931</td>
</tr>
</tbody>
</table>

Québec

The Québec area anticipates adequate resources to meet demand for the 2015-16 winter season. The current 2015-16 peak forecast (normal) is 38,192 MW and the forecasted operating margin is 2,126 MW for the peak week. This includes known maintenance and derates of 3,917 MW, including scheduled generator maintenance and hydraulic as well as mechanical restrictions and wind generation derating. Table 1.8 shows the factors included in the operating margin calculation. An extreme forecast scenario has also been evaluated and the margin anticipated is 1,116 MW.

Table 1.8: Québec Operable Capacity Forecasts

<table>
<thead>
<tr>
<th>Month</th>
<th>Normal Forecast (MW)</th>
<th>Extreme Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>45,380</td>
<td>45,380</td>
</tr>
<tr>
<td>Net Interchange</td>
<td>-44</td>
<td>-44</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>45,336</td>
<td>45,336</td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>1,899</td>
<td>1,899</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>3,917</td>
<td>3,917</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>1,500</td>
<td>1,500</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>1,500</td>
<td>1,500</td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>38,192</td>
<td>39,202</td>
</tr>
<tr>
<td>Operating Margin</td>
<td>2,126</td>
<td>1,116</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
<td>5.6%</td>
<td>2.8%</td>
</tr>
</tbody>
</table>

If Québec real-time peak demands are higher than forecasted, a number of measures are available to the System Control personnel and are listed in Section 6: Operational Readiness.
Québec’s area energy requirements are met for the greatest part by hydro generating stations located on different river systems and scattered over a large territory. The major plants are backed by multiannual reservoirs (water reserves lasting more than one year). Due to the multi-year reservoirs, a single year of low water inflow cannot adversely impact the reliability of energy supply. However, a series of consecutive dry years may require some operating measures, such as the reduction of exports or capacity purchase from neighbouring areas. To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows totalling 64 TWh or a sequence of 4 years totalling 98 TWh, and having a 2 percent probability of occurrence. The use of operating measures and the hydro reservoirs will be managed accordingly. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. Such documents can be found on the Régie de l’Énergie du Québec website.⁴

The table below summarizes projected capacity and margins by Reliability Coordinator area. Appendix I shows these projections for the entire winter operation period respecting normal demand forecasts.

**Projected Capacity Analysis by Reliability Coordinator area**

<table>
<thead>
<tr>
<th>Area</th>
<th>Measure</th>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derate MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Unplanned Net Margin MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPCC</td>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>163,628</td>
<td>820</td>
<td>164,448</td>
<td>110,127</td>
<td>4,412</td>
<td>16,694</td>
<td>8,852</td>
<td>14,592</td>
<td>18,595</td>
</tr>
<tr>
<td>Maritimes</td>
<td>Peak Week</td>
<td>24-Jan-16</td>
<td>7,788</td>
<td>-200</td>
<td>7,588</td>
<td>5,509</td>
<td>256</td>
<td>971</td>
<td>693</td>
<td>279</td>
<td>392</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>24-Jan-16</td>
<td>7,788</td>
<td>-200</td>
<td>7,588</td>
<td>5,509</td>
<td>256</td>
<td>971</td>
<td>693</td>
<td>279</td>
<td>392</td>
</tr>
<tr>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>7,788</td>
<td>-200</td>
<td>7,588</td>
<td>5,265</td>
<td>242</td>
<td>971</td>
<td>693</td>
<td>693</td>
<td>279</td>
<td>622</td>
</tr>
<tr>
<td>New England</td>
<td>Peak Week</td>
<td>10-Jan-16</td>
<td>32,872</td>
<td>1,283</td>
<td>34,098</td>
<td>21,077</td>
<td>587</td>
<td>763</td>
<td>2,375</td>
<td>7,020</td>
<td>3,450</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>22-Nov-15</td>
<td>32,857</td>
<td>969</td>
<td>33,826</td>
<td>18,988</td>
<td>465</td>
<td>6,554</td>
<td>2,375</td>
<td>4,328</td>
<td>2,046</td>
</tr>
<tr>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>32,872</td>
<td>1,226</td>
<td>34,098</td>
<td>21,077</td>
<td>587</td>
<td>682</td>
<td>2,375</td>
<td>7,020</td>
<td>3,531</td>
<td>3,531</td>
</tr>
<tr>
<td>New York</td>
<td>Peak Week</td>
<td>13-Dec-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>24,515</td>
<td>963</td>
<td>3,976</td>
<td>2,620</td>
<td>4,324</td>
<td>7,253</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>13-Dec-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>24,515</td>
<td>963</td>
<td>3,976</td>
<td>2,620</td>
<td>4,324</td>
<td>7,253</td>
</tr>
<tr>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>23,784</td>
<td>963</td>
<td>3,976</td>
<td>2,620</td>
<td>4,324</td>
<td>8,567</td>
<td>8,567</td>
</tr>
<tr>
<td>Ontario</td>
<td>Peak Week</td>
<td>3-Jan-16</td>
<td>36,276</td>
<td>-500</td>
<td>35,776</td>
<td>22,389</td>
<td>555</td>
<td>7,075</td>
<td>1,664</td>
<td>1,498</td>
<td>3,705</td>
</tr>
<tr>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>36,276</td>
<td>-500</td>
<td>35,776</td>
<td>21,809</td>
<td>721</td>
<td>7,864</td>
<td>1,664</td>
<td>1,411</td>
<td>3,749</td>
<td>3,749</td>
</tr>
<tr>
<td>Québec</td>
<td>Peak Week</td>
<td>17-Jan-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>38,192</td>
<td>1,899</td>
<td>3,917</td>
<td>1,500</td>
<td>1,500</td>
<td>2,126</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>17-Jan-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>38,192</td>
<td>1,899</td>
<td>3,917</td>
<td>1,500</td>
<td>1,500</td>
<td>2,126</td>
</tr>
<tr>
<td>NPCC Peak Week</td>
<td>17-Jan-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>38,192</td>
<td>1,899</td>
<td>3,917</td>
<td>1,500</td>
<td>1,500</td>
<td>2,126</td>
<td>2,126</td>
</tr>
</tbody>
</table>
**Generation Resource Changes**

The following Table lists the recent and anticipated generation resource additions and retirements. Generation adjustments may be reflected as an increase or decrease in MW output, recognizing changes due to mechanical, environmental or performance audits.

**Table 4: Resource Changes from Winter 2014-15 through Winter 2015-16**

<table>
<thead>
<tr>
<th>Area</th>
<th>Generation Facility</th>
<th>Nameplate Capacity (MW)</th>
<th>Fuel Type</th>
<th>In Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>COMFIT Wind – various small wind farms</td>
<td>60.7</td>
<td>Wind</td>
<td>From Winter 2014-15 through 2015-16</td>
</tr>
<tr>
<td></td>
<td>COMFIT</td>
<td>4.2</td>
<td>Biomass</td>
<td>From Winter 2014-15 through 2015-16</td>
</tr>
<tr>
<td></td>
<td>COMFIT Wind</td>
<td>14</td>
<td>Wind</td>
<td>Q1 - 2016</td>
</tr>
<tr>
<td></td>
<td>Sable Wind</td>
<td>13.8</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>South Canoe Wind</td>
<td>102</td>
<td>Wind</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Seasonal Adjustments</td>
<td>7.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>202</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area</td>
<td>Generation Facility</td>
<td>Nameplate Capacity (MW)</td>
<td>Fuel Type</td>
<td>In Service Date</td>
</tr>
<tr>
<td>--------------</td>
<td>---------------------------</td>
<td>-------------------------</td>
<td>------------------</td>
<td>-----------------</td>
</tr>
<tr>
<td>New England</td>
<td>Canal 2 (uprate)</td>
<td>256</td>
<td>Dual Fuel</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Bucksport (uprate)</td>
<td>87</td>
<td>Natural Gas</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Oakfield II Wind</td>
<td>148</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Assorted small facilities</td>
<td>52</td>
<td>Various</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>Seasonal Adjustments</td>
<td>-144</td>
<td>Various derates</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>429</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>Bowline 2 (uprate)</td>
<td>+374</td>
<td>Oil/Nat. Gas</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Dunkirk 2 (mothball)</td>
<td>-75</td>
<td>Coal</td>
<td>Q1 - 2016</td>
</tr>
<tr>
<td></td>
<td>Net Nameplate Capacity Change</td>
<td>+299</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Seasonal ICAP Adjustments</td>
<td>+50</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>349</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area</td>
<td>Generation Facility</td>
<td>Nameplate Capacity (MW)</td>
<td>Fuel Type</td>
<td>In Service Date</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>----------------------------------------------</td>
<td>-------------------------</td>
<td>--------------</td>
<td>----------------</td>
</tr>
<tr>
<td>Ontario</td>
<td>Smoky Falls G1, G2, G3</td>
<td>264</td>
<td>Water</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Bluewater Wind Energy Centre</td>
<td>60</td>
<td>Wind</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Kipling Unit 3</td>
<td>79</td>
<td>Water</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Thunder Bay G3 Biomass Conversion</td>
<td>153</td>
<td>Biomass</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Adelaide Wind Power</td>
<td>40</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Nuclear Adjustments</td>
<td>31</td>
<td>Nuclear</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Dufferin Wind Power</td>
<td>91.3</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Adelaide Wind Energy Centre</td>
<td>60</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Bornish Wind Energy Centre</td>
<td>73.5</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Grand Renewable Energy Park</td>
<td>100</td>
<td>Solar</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Goulais Wind Farm</td>
<td>25</td>
<td>Wind</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>K2 Wind Project</td>
<td>270</td>
<td>Wind</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Thunder Bay Condensing Turbine Project</td>
<td>40</td>
<td>Biomass</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Empire</td>
<td>10</td>
<td>Solar</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Cedar Point Wind Power Project Phase II</td>
<td>100</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Abitibi</td>
<td>10</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Kingston Solar Project</td>
<td>100</td>
<td>Solar</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Martin’s Meadows</td>
<td>10</td>
<td>Solar</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Bow Lake Phase I</td>
<td>20</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Long Lake</td>
<td>10</td>
<td>Solar</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Grand Valley Wind Farms Phase III</td>
<td>40</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Green Electron Power Project</td>
<td>298</td>
<td>Gas</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Armow Wind Project</td>
<td>180</td>
<td>Wind</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Total Adjustments</td>
<td>-416.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Retirement</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>2064.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>1648</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Québec

<table>
<thead>
<tr>
<th>Capacity (MW)</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>La Romaine-1 First Generator</td>
<td>135</td>
</tr>
<tr>
<td>Hydro Generation Adjustments</td>
<td>47</td>
</tr>
<tr>
<td>Hydro Contract Adjustment</td>
<td>155</td>
</tr>
<tr>
<td>Wind Additions</td>
<td>373</td>
</tr>
<tr>
<td>Biomass Additions</td>
<td>5</td>
</tr>
<tr>
<td>Biomass Retirement</td>
<td>-5</td>
</tr>
<tr>
<td>Private Producers Adjustments</td>
<td>-11</td>
</tr>
<tr>
<td>Total Reduction</td>
<td>-16</td>
</tr>
<tr>
<td>Total Addition</td>
<td>715</td>
</tr>
<tr>
<td>Net Total</td>
<td>699</td>
</tr>
</tbody>
</table>

Maritimes

Since winter 2014-15, there has been an additional 176.5 MW of wind generation placed in service along with a 4.2 MW biomass generator. There is an additional 14 MW of wind generation scheduled to be in service by the Maritimes forecasted winter peak.

New England

New generation improvements since the previous winter assessment include the Canal 2 uprate, Oakfield II Wind Farm, and small generator installations with nameplate capacities totaling 52 MW. All these improvements have or are expected to become commercial before the 2015-16 winter assessment period. Additionally, one wood/wood refuse generator at Bucksport, capable of producing 87 MW (72 MW of SCC), had moved from behind the meter during the summer capacity period.

New York

Since the winter 2014-15 winter season, the only significant change to generation in New York is the 374 MW nameplate uprate of the Bowline 2 facility. It is anticipated that the coal fired Dunkirk 2 will mothball at the end of 2015 and the coal fired Huntley units 67 & 68 (436 MW nameplate total) will retire in March of 2016.

Ontario

By the end of the winter 2015-16 assessment period, the total capacity in Ontario is expected to increase by 1648 MW from the 2014-15 winter assessment. When looking specifically at the 2015-16 winter assessment timeframe, the expected increase in capacity is 778MW which includes 340 MW of wind, 140 MW of solar and 298 MW of gas generation. This equates to a 424 MW addition to the operable capacity.
Québec

By the end of 2015, the first of two hydro generators of La-Romaine-1 (135 MW each) will be commissioned. The second generator is expected to be commissioned in spring 2016. At this time, the nameplate capacity of La-Romaine complex will have reached 910 MW on a 1,550 MW total (by the year 2020). For the upcoming winter, nameplate wind capacity of the Québec area is expected to be 3,254 MW, a 373 MW increase since the last winter assessment and biomass production should have a net decrease of 11 MW. A specific hydro contract has been accounted differently in this assessment and led to a 155 MW hydro adjustment but the same value has been accounted for within the Known Maintenance & Derates category. No net impact on the margins calculation will be observed. Other hydro capacity adjustments have been made (+47 MW) and Installed Capacity is now 45,380 MW, a net 699 MW increase since the last winter assessment. There are no significant resource retirements planned for the 2015-16 winter period.
Fuel Infrastructure by Reliability Coordinator area

The following depict installed generation resource profiles for each Reliability Coordinator (Figure 6.1) area and the NPCC collectively (Figure 6.2) by primary fuel supply infrastructure.

Figure 6.1: Installed Generation Fuel Type by Reliability Coordinator Area
Figure 6.2: Installed Capacity Fuel Profiles for NPCC

NPCC Installed Capacity Profiles for Winter 2015-16

- Hydro/Tidal: 31.0%
- Gas: 15.5%
- Nuclear: 14.2%
- Dual Fuel: 13.1%
- Oil: 9.2%
- Wind: 7.0%
- Coal: 6.3%
- Other: 3.7%
Wind Capacity Analysis by Reliability Coordinator Area

For the 2015-16 Winter Operating Period, installed (nameplate) wind capacity accounts for approximately 7 percent of the total NPCC Installed Capacity during the coincident peak demand. After applying adequate derate factors, the amount of wind generation counted towards capacity is approximately 1.9 percent. Reliability Coordinator areas have distinct methods of accounting for this generation and are continuing to develop their knowledge regarding the operation and integration of wind generation in terms of capacity forecasting and utilization factor.

Table 4 below illustrates the nameplate wind capacity in NPCC for the 2015-16 winter operating period. To account for the resource variability, the Maritimes, New York, Ontario, and Québec areas include the entire wind nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Derates section to account for the fact that some of the capacity will not be producing energy at the time of peak. New England reduces the nameplate capacity and reflects this reduced capacity directly in the Installed Capacity section of the Load and Capacity Table.

<table>
<thead>
<tr>
<th>Reliability Coordinator area</th>
<th>Nameplate Capacity Winter 2015-16 (MW)</th>
<th>Capacity After Applied Derating Factor (MW)</th>
<th>Capacity Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>1,091</td>
<td>256</td>
<td>23.5 percent</td>
</tr>
<tr>
<td>New England*</td>
<td>1,011</td>
<td>238</td>
<td>23.5 percent</td>
</tr>
<tr>
<td>New York**</td>
<td>1,461</td>
<td>454</td>
<td>31 percent</td>
</tr>
<tr>
<td>Ontario</td>
<td>3,549</td>
<td>1,323</td>
<td>38 percent</td>
</tr>
<tr>
<td>Québec</td>
<td>3,254</td>
<td>945</td>
<td>29 percent</td>
</tr>
<tr>
<td>Total</td>
<td><strong>10,366</strong></td>
<td><strong>3,216</strong></td>
<td><strong>31 percent</strong></td>
</tr>
</tbody>
</table>

*Total wind nameplate capacity in New England is 1,011 MW; however, only 238 MW have established seasonal claimed capability.

**Total wind nameplate capacity in New York is 1,746 MW; however, only 1,461 MW participate in the ICAP market.
**Maritimes**

Wind projected capacity is derated to its demonstrated output for each summer or winter capability period. In New Brunswick, Prince Edward Island and Northern Maine Independent System Administrator (NMISA) the wind facilities that have been in production over a three year period, a derated monthly average is calculated using metering data from previous years over each seasonal assessment period. For those that have not been in service that length of time (three years), the deration of wind capacity in the Maritimes Area is based upon results from the Sept. 21, 2005 NBSO report “Maritimes Wind Integration Study”. This wind study showed that the effective capacity from wind projects, and their contribution to loss of load expectation (LOLE) was equal to or better than their seasonal capacity factors.

Nova Scotia applies an 8 percent capacity value to installed wind capacity (92 percent derated) throughout the year. This figure was calculated via a Cumulative Frequency Analysis of historical wind data over 4 years (2010-2013). The top 10 percent of load hours were analyzed to reflect peak load conditions, and a 90 percent confidence limit was selected as the critical value. This analysis showed that NS Power can expect to have at least 8 percent of installed wind capacity producing energy in 90 percent of peak hours.

**New England**

During the 2015-16 winter assessment period, New England has derated the wind resources by 76.5 percent as a result of established winter claimed capability audits (CCAs). Over 1,000 MW of wind resources are interconnected to the grid and wind-powered generation facilities make up a significant portion of the proposed generation projects in New England.

**New York**

In 2015 there were 6,264 MW of nameplate renewable resource capacity in New York. This includes 1,746 MW of nameplate wind capacity. As indicated above only 1,461 MW participates in the New York ICAP market. The ICAP nameplate capacity is counted at full value towards the Installed Capacity for New York and is derated by 69 percent based on historical performance data when determining operating margins.

In 2014, 35,756 gigawatt-hours of New York’s electricity was produced by renewable resources (hydropower, wind, solar and other) representing approximately 25 percent of New York’s electric generation.
Ontario

For Ontario, monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values in percentage of installed capacity are determined from a combination of actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The simulated 10-year historic wind data will be included until 10-years of actual wind data is accumulated; at which point the simulated wind data will be phased out of the WCC calculation. From an adequacy assessment perspective, although the entire install capacity of the wind generation is included in Ontario’s total installed capacity number, the appropriate penalty is applied to the ‘Known Maint./Derate/Bottled Cap.’ Number to ensure the WCC values are accounted for when assessing net margins.

Québec

In the Québec area, wind generation plants are owned and operated by Independent Power Producers (IPPs). Nameplate capacity will be 3,254 MW for the 2015-16 winter peak period of which 212 MW is under contract with Hydro-Québec Production (HQP – Generator Owner). 104 MW of this total is de-rated by 100 percent and 108 MW is de-rated by 70 percent. The rest (3,042 MW) is under contract with Hydro-Québec Distribution (HQQ - Resources Planner and Load Supply Entity) and is de-rated by 70 percent for this assessment. During the 2014-15 winter peak demand day, Wind Power Plants were generating 978 MW; 34 percent of the wind nameplate capacity which is comparable to the forecast used in this assessment (29 percent of total wind capacity during the winter peak period). Under these assumptions, the wind power contribution for the next winter peak period is estimated at 945 MW on a 3,254 MW total (an overall derating of 71 percent).
**Demand Response Programs**

Each Reliability Coordinator area utilizes various methods of demand management. The table below summarizes the expected demand response available within the NPCC area for the forecasted peak demand week of January 17, 2016 and compared to the 2014-15 winter assessment.

<table>
<thead>
<tr>
<th>Reliability Coordinator Area</th>
<th>2015-16 Active Demand Response (MW)</th>
<th>2014-15 Active Demand Response (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>256</td>
<td>246</td>
</tr>
<tr>
<td>New England</td>
<td>587</td>
<td>656</td>
</tr>
<tr>
<td>New York</td>
<td>963</td>
<td>892</td>
</tr>
<tr>
<td>Ontario</td>
<td>555</td>
<td>728</td>
</tr>
<tr>
<td>Québec</td>
<td>1,899</td>
<td>1,708</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,412</strong></td>
<td><strong>4,230</strong></td>
</tr>
</tbody>
</table>

The forecasted 2015-16 winter active demand response available for NPCC is an increase of 182 MW from the forecasted 4,230 MW of winter active demand response available during 2014-15.

**Maritimes**

Interruptible loads are forecast on a weekly basis and range between 236 MW and 332 MW. The values can be found in Table AP-2 and are available for use when corrective action is required within the Area.

**New England**

In New England, 587 MW of active demand resources are expected to be available on peak for the 2015-16 winter assessment period. The active demand resources consist of 413 MW of real-time demand response (RTDR) and 174 MW of real-time emergency generation (RTEG), both of which can be activated with the implementation of ISO-NE
Operating Procedure No. 4 (OP 4), Action during a Capacity Deficiency. These active demand resources can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of RTDR, which is implemented to manage operating reserve requirements. Action 6, which is the dispatch of RTEG resources, may be implemented to maintain 10-minute reserve.

In addition to active demand resources, 1,663 MW of passive demand resources (i.e., energy efficiency and conservation) are treated as demand reducers in this report and are accounted for in the load forecast of 21,077 MW. Without the effects of passive demand resources, the 2015-16 winter forecast would equate to 22,740 MW. Passive demand measures include installed products, equipment, and systems, as well as services, practices, and strategies, at end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. The amount of energy efficiency is based on capacity supply obligations (CSOs) in the Forward Capacity Market.

New York

The NYISO has three demand response programs to support system reliability. The NYISO currently projects 963 MW of total demand response available for the 2015-16 winter season.

The Emergency Demand Response Program (EDRP) provides demand resources an opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price (“LBMP”) for energy consumption curtailments provided when the NYISO calls on the resource. Resources must be enrolled through Curtailment Service Providers (“CSPs”), which serve as the interface between the NYISO and resources, in order to participate in EDRP. There are no obligations for enrolled EDRP resources to curtail their load during an EDRP event.

The Installed Capacity (ICAP) Special Case Resource program allows demand resources that meet certification requirements to offer Unforced Capacity (“UCAP”) to Load Serving Entities (“LSEs”). The load reduction capability of Special Case Resources (“SCRs”) may be sold in the ICAP Market just like any other ICAP Resource; however, SCRs participate through Responsible Interface Parties (RIPs), which serve as the interface between the NYISO and the resources. RIPs also act as aggregators of SCRs. SCRs that have sold ICAP are obligated to reduce their system load when called upon by the NYISO with two or more hours’ notice, provided the NYISO notifies the Responsible Interface Party a day ahead of the possibility of such a call. In addition, enrolled SCRs are subject to testing each Capability Period to verify their capability to achieve the amount of enrolled load reduction. Failure of an SCR to reduce load during an event or

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test results in a reduction in the amount of UCAP that can be sold in future periods and could result in penalties assessed to the applicable RIP in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the NYISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, RIPS are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

The Targeted Demand Response Program (“TDRP”), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources 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.

Ontario

Ontario’s demand response is comprised of the following programs: peaksaver, dispatchable loads, Capacity Based Demand Response (CBDR), time-of-use (TOU) tariffs and the Industrial Conservation Initiative (ICI). Dispatchable loads and CBDR resources can be dispatched in the same way that generators are, whereas TOU, ICI, conservation impacts and embedded generation output are factored into the demand forecast as load modifiers. For the winter assessment period, the capacity of the demand response program consists of 677 MW of dispatchable load, 514 MW of CBDR resources and 0 MW of Peaksaver resources. Peak saver is an air conditioning, electric hot water heater, and swimming pool-pump cycling program, which is not available during the winter period. Although the total demand response capacity is 1,191 MW, the effective capacity is 555 MW due to program restrictions and market participant actions. During peak periods of the year, market participants take independent action to reduce their consumption for economic reasons, reducing the available capacity for demand measures.

An annual demand response auction is currently being developed by the IESO to procure DR capacity through a competitive mechanism. The quantity of DR capacity that the auction will seek to procure will be equivalent to the quantity expiring from the transitional Capacity Based Demand Response (CBDR). The combined total of DR capacity in the CBDR program and selected through the DR auction will maintain the approximately 500 MW that was previously procured under DR2 and DR3 contracts. The first Demand Response Auction will be held in December 2015 for summer and winter commitment periods (May 1 – October 31, 2016 and November 1, 2016 – April 30, 2017, respectively).

Québec
The Demand Response and Energy Efficiency/Conservation programs have an estimated combined impact of 4,100 MW under winter peak conditions (2015-16) as follows:

1. Demand forecasts take into account the load shaving resulting from the residential dual energy program, a rate option for residential customers equipped with a dual energy space heating system (electric/fuel oil). When the outside temperature falls below a given level (-12°C for Montréal), the space heating system automatically runs on the fuel oil and the electricity used during that period is billed at higher rates. The impact of this program on peak load demand is estimated to be approximately 600 MW over the period assessment.

2. In the Québec subregion, Demand Response (DR) programs are specifically designed for peak-load reduction during winter operating periods. DR consists of interruptible demand programs for large industrial customers, treated as supply-side resources totaling 1,649 MW for the 2015-16 winter period. It is 191 MW more than last winter period. DR programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand. Interruptible load program specifications differ among programs and participating customers. They usually allow for one or two calls for reduction per day and between 40 to 100 hours load interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed. Before the peak period, generally during the fall season, all customers are regularly contacted in order to reaffirm their commitment to provide capacity when called, during peak periods.

3. The Energy Efficiency/Conservation programs impact is evaluated at 1,590 MW for the 2015-16 Winter peak period and is included in the demand forecast (active and to be deployed programs). These programs have been in place for several years and the records show that customer response is very reliable.

4. In addition, the voltage reduction program consists of 250 MW. This program allows the system operator to strategically reduce voltage across designated portions of its distribution system, within regulatory guideline in order to reduce peak demand.
5. Transmission Adequacy

Regional Transmission studies specifically identifying interface transfer capabilities in NPCC are not normally conducted. However, NPCC uses the results developed in each of the NPCC Reliability Coordinator areas and compiles them for all major interfaces and for significant load areas (Appendix III). Recognizing this, the CO-12 working group reviewed the transfer capabilities between the Balancing Authority Areas of NPCC under normal and peak demand configurations.

Table 7: NPCC – Recent and Future Transmission Additions

<table>
<thead>
<tr>
<th>NPCC Sub-Area</th>
<th>Transmission Project</th>
<th>Voltage (kV)</th>
<th>In Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>Onslow Substation Upgrade</td>
<td>345 KV</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td>New England</td>
<td>3024 Line (Albion Road – Coopers Mill)</td>
<td>345 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Coopers Mill T3 Transformer</td>
<td>345 / 115 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>3025 Line (Coopers Mill - Larrabee)</td>
<td>345 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>254 Line (Orrington – Coopers Mill)</td>
<td>115 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Coopers Mill 40 MVAr Reactors (x2)</td>
<td>115 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>3271 Line (Card – Lake Road)</td>
<td>345 kV</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>341 Line (Lake Road – West Farnum)</td>
<td>345 kV</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>366 Line (West Farnum – Millbury)</td>
<td>345 kV</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td>NPCC Sub-Area</td>
<td>Transmission Project</td>
<td>Voltage (kV)</td>
<td>In Service</td>
</tr>
<tr>
<td>---------------</td>
<td>----------------------</td>
<td>--------------</td>
<td>------------</td>
</tr>
<tr>
<td>New York</td>
<td>Five Mile Rd (New Station)</td>
<td>345</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Coopers Corners Switched Shunt Reactor (200 MVAr)</td>
<td>345</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Mainesburg Station (New PJM Station at NYCA Interface)</td>
<td>345</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Moses Cap Banks</td>
<td>115</td>
<td>Q3 - 2016</td>
</tr>
<tr>
<td></td>
<td>Farmers Valley (New PJM Station at NYCA Interface)</td>
<td>345</td>
<td>Q3 - 2016</td>
</tr>
<tr>
<td></td>
<td>Marcy South Series Compensation</td>
<td>345</td>
<td>Q3 - 2016</td>
</tr>
<tr>
<td></td>
<td>Ramapo-Sugarloaf-Rock Tavern (New Line)</td>
<td>345</td>
<td>Q3 - 2016</td>
</tr>
<tr>
<td></td>
<td>Goethals Feeder Separation</td>
<td>345</td>
<td>Q3 - 2016</td>
</tr>
<tr>
<td>Ontario</td>
<td>Hanmer Transformer Replacement</td>
<td>500kV</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td></td>
<td>Lambton TS Station Upgrade</td>
<td>230kV</td>
<td>Q4 - 2015</td>
</tr>
<tr>
<td>Québec</td>
<td>New 735 kV Aux Outardes switching substation</td>
<td>735</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Two 735 kV existing lines redirected in new Aux Outardes substation</td>
<td>735</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>New 3 mile line between new Aux Outardes substation and existing Micoua substation</td>
<td>735</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>New 16 mile line between La Romaine 2 substation and La Romaine 1 generating station</td>
<td>735 operated at 315</td>
<td>Q4 - 2015</td>
</tr>
</tbody>
</table>
The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels, Inter-Region, Inter-Area and Intra-Area.

**Inter-Regional Transmission Adequacy**

**Ontario – Manitoba Interconnection**

The Ontario – Manitoba interconnection consists of two 230 kV circuits and one 115 kV circuit. The transfers on the 230 kV are constrained by stability and thermal limitations; 300 MW for exports and imports. The transfers on the 115 kV is limited to 68 MW into Ontario, with no export allowed.

**Ontario – Minnesota Interconnection**

The Ontario – Minnesota interconnection consists of a single 115 kV circuit, with total transfer capability constrained by stability and thermal limitations to 150 MW exports and 100 MW imports.

**Ontario – Michigan Interconnection**

The Ontario – Michigan interconnection consists of two 230/345 kV circuits, one 230/115 kV circuit, and one 230 kV circuit which are all constrained by thermal limitations. There are four phase angle regulators presently in service with a total transfer capability export limit of 1,750 MW and an import limit of 1,750 MW.

**New York – PJM Interconnection**

The New York – PJM interconnection consists of one PAR controlled 500/345 kV circuit, two 345 kV circuits, a VFT controlled 345/230 kV circuit, three PAR controlled 345/230 kV circuits, two free flowing 230 kV circuits, three 115 kV circuits, and a 138/69 kV network serving a load pocket through the New York system from PJM.

Two new stations have been installed at the New York-PJM interface. The Mainesburg 345 kV station in PJM taps the Homer City-Watercure 30 345 kV line and changes the interface definition to Mainesburg-Watercure 30. The Five Mile Road 345 kV station taps the Homer City-Stolle Rd. 37 345 kV line and changes the interface definition to Homer City-Five Mile Rd. 37.
**Inter-Area Transmission Adequacy**

Appendix III provides a summary of the Total Transfer Capabilities (TTC) on the interfaces between NPCC Reliability Coordinator areas and for some specific load zone areas. They also indicate the corresponding Available Transfer Capabilities (ATC) based on internal limitations or other factors and indicate the rationale behind reductions from the normal transfer capability.

The table below summarizes the Total Transfer Capabilities (TTC) between each region. Full details can be found in Appendix III.

<table>
<thead>
<tr>
<th>Total Transfer Capability Summary</th>
<th>(MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Transfers from Maritimes to</strong></td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td>770</td>
</tr>
<tr>
<td>New England</td>
<td>1000</td>
</tr>
<tr>
<td><strong>Transfers from New England to</strong></td>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
<td>550</td>
</tr>
<tr>
<td>New York</td>
<td>1,730</td>
</tr>
<tr>
<td>Québec</td>
<td>1,370</td>
</tr>
<tr>
<td><strong>Transfers from New York to</strong></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>2,130</td>
</tr>
<tr>
<td>Ontario</td>
<td>1,650</td>
</tr>
<tr>
<td>PJM</td>
<td>1,615</td>
</tr>
<tr>
<td>Québec</td>
<td>1,100</td>
</tr>
<tr>
<td><strong>Transfer from Ontario to</strong></td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>1,800</td>
</tr>
<tr>
<td>MISO</td>
<td>2,200</td>
</tr>
<tr>
<td>Québec</td>
<td>2,170</td>
</tr>
<tr>
<td><strong>Transfers from Québec to</strong></td>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
<td>773 + radial load</td>
</tr>
<tr>
<td>New England</td>
<td>2,275</td>
</tr>
<tr>
<td>New York</td>
<td>1,999</td>
</tr>
<tr>
<td>Ontario</td>
<td>2,955</td>
</tr>
</tbody>
</table>
**Area Transmission Adequacy Assessment**

**Maritimes**

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Winter Operating Period. Part of the Total Transfer Capability (TTC) calculation with HQ is based on the ability to transfer radial loads onto the HQ system. The radial load value will be calculated monthly and HQ will be notified of the changes (See Appendix III). The Onslow substation transmission upgrade has increased the internal (Nova Scotia) transmission corridor transfer limits by alleviating the most severe contingency.

**New England**

For ISO-NE, new bulk power transmission facilities have been placed into service for the 2015-16 winter assessment period. With the completion of the multiyear Maine Power Reliability Program (MPRP) transmission project, more than 450 miles of new or rebuilt 345 kV and 115 kV transmission lines have been placed into service, in addition to five new substations, and six major substations have been modified. Additionally, six special protection systems (SPSs) and one automatic closing scheme (ACS) have been retired. Other improvements include load-serving and energy-transfer capabilities across multiple interfaces within the State of Maine, and import/export capabilities with the Maritimes.

The Interstate Reliability Project (IRP), a portion of the New England East–West Solution (NEEWS), is another major transmission project that offers further improvements to New England’s transmission system.

The 2371 line, a new 345 kV path in Connecticut from Card to Lake Road, went into service during summer 2015. Two new 345 kV paths—the 341 line from Lake Road to West Farnum (Connecticut to Rhode Island) and the 366 line from West Farnum to Millbury (Rhode Island to Massachusetts)—are both expected to be placed into service during winter 2015-16. These lines will further improve Connecticut’s and Rhode Island’s import and export transfer capabilities and New England’s east-to-west and west-to-east transfer capabilities.

**New York**

For the winter 2015-16 season New York expects significant changes to be made to the system. A switched shunt reactor at the Coopers Corners 345 kV station went in-service in Q3 of 2015. The reactor is intended to be used to alleviate high voltages in the area during light load periods which typically occur during early morning hours of shoulder months.
The Transmission Owner Transmission Solutions (TOTS) consists of three distinct transmission projects approved by the PSC as part of the Indian Point Contingency Plan in October 2013 and are projected by the Transmission Owners to be in service by summer 2016. The objective of the plan is to increase transfer capability into Southeast New York. The Marcy South Series Compensation project includes adding compensation to the Marcy South transmission corridor through the installation of series capacitors, and includes re-conductoring the Fraser-Coopers Corners 345 kV line. The Rock Tavern-Ramapo project will add a second Rock Tavern-Ramapo 345 kV line and create a Sugarloaf 345/138 kV connection to the Orange and Rockland system. The Marcy South Series Compensation and Rock Tavern-Ramapo projects together will increase the transfer capability from upstate to downstate New York. The Staten Island Unbottling project will relieve transmission constraints between Staten Island and the rest of New York City through the reconfiguration of two substations and the forced cooling of four existing 345 kV feeders. Winter outages to key elements of the 345 kV system will be required for these projects and are being coordinated to minimize system impacts and should not affect reliable system operation.

**Ontario**

For this Winter Operating Period, Ontario’s transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmissions outages under normal and extreme conditions. With all transmission elements in service, the theoretical maximum capability for exports from Ontario is up to 6,359 MW, and 7,025 MW for imports. These values represent theoretical levels that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 5,200 MW.

Outages affecting neighboring jurisdictions can be found in Table 8: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the winter season.

**Québec**

The Québec area is winter-peaking. No transmission equipment is scheduled for maintenance outages during this period.

A major transmission project presently underway is the construction of the Romaine River Hydro Complex. At the end of 2014, the first phase, La Romaine-2 (640 MW) generating station, has been integrated at the Arnaud 735/315/161-kV substation with a 262 km (162 miles) line initially operated at 315 kV. One 315/161-kV, 500-MVA transformer has been added commissioned at Arnaud substation for this project.
By the end of 2015, the first of two generators of La-Romaine-1 (135 MW each) will be commissioned. This new hydro generating station will be integrated into La-Romaine-2 substation with a 16 mile 315 kV line. The second generator is expected to be in service by summer 2016.

This project has required the construction of a new 735-kV switching station named “Aux Outardes” that is located between the existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua. This project was initially planned to be in-service by the end of 2014 but was commissioned in summer 2015.
**Area Transmission Outage Assessment**

The section below outlines any known scheduled outages on interfaces between Reliability Coordinators.

### Table 9: Area Transmission Outage Assessment

**Maritimes**

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Interface Impacted</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

**New England**

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Interface Impacted</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYISO</td>
<td>NE-NY (E205W)</td>
<td>7-Dec-15</td>
<td>11-Dec-15</td>
<td>Reduction dependent upon dispatch</td>
</tr>
<tr>
<td>NYISO</td>
<td>NE-NY (PV20)</td>
<td>1-Jan-16</td>
<td>29-Jan-16</td>
<td>Reduction dependent upon dispatch</td>
</tr>
<tr>
<td>HQ</td>
<td>Highgate (PV20)</td>
<td>175 MW (Export)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### New York

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Interface Impacted</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISONE</td>
<td>NE-NY (Berkshire-Alps 393)</td>
<td>30-Nov-15</td>
<td>4-Dec-15</td>
<td>-100 Imp -300 Exp</td>
</tr>
<tr>
<td>ISONE</td>
<td>NNC (Northport-Norwalk Cable for Berkshire-Alps 393 O/S)</td>
<td>30-Nov-15</td>
<td>4-Dec-15</td>
<td>-100 Imp -100 Exp</td>
</tr>
<tr>
<td>ISONE</td>
<td>NE-NY (Long Mtn-Pl Vly 398)</td>
<td>5-Dec-15</td>
<td>19-Dec-15</td>
<td>-700 Imp -300 Exp</td>
</tr>
<tr>
<td>ISONE</td>
<td>NNC (Northport-Norwalk Cable for Long Mtn-Pl Vly 398 O/S)</td>
<td>5-Dec-15</td>
<td>19-Dec-15</td>
<td>-100 Imp -100 Exp</td>
</tr>
</tbody>
</table>

### Ontario

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Interface Impacted</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>NY</td>
<td>PA302</td>
<td>17-Dec-15</td>
<td>18-Dec-15</td>
<td>400 MW (Export) / 600 MW (Import)</td>
</tr>
<tr>
<td>HQ</td>
<td>D4Z</td>
<td>30-Nov-15</td>
<td>17-Dec-15</td>
<td>D4Z transfer limit to 0 MW</td>
</tr>
</tbody>
</table>

### Québec

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Interface Impacted</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
<td></td>
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</tbody>
</table>
6. **Operational Readiness for Winter 2015-16**

**Maritimes**

*Voltage Control*

The Maritimes Area, in addition to the reactive capability of the generating units, employs a number of capacitors, reactors, synchronous condensers and a Static Var Compensator in order to provide local area voltage control.

*Operational Procedures*

The Maritimes Area is a winter peaking system and does not anticipate any operational issues. In the event where the real-time peak demand was higher than expected, there are Emergency Operations and Planning procedures in place. Some of the actions within these procedures include the following:

- Use of interruptible load curtailments
- Purchase of Emergency Energy in accordance with Interconnection Agreements
- Curtailment of export energy sales
- Public Appeals
- Shedding of Firm Load

For changes to internal operating conditions (i.e. transmission and or generator outages) these will be handled with a Short Term Operating Procedures (STOP) which would outline any special operating conditions.

*Winter Preparation*

As part of the winter planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.

*Wind Integration*

Monitoring of thermal unit dispatch under high wind / low load periods (e.g. shoulder season overnight hours) is an area of focus; work to assess steam unit minimum loads and minimum steam system configurations is ongoing.
New England

Voltage Control

ISO New England repeatedly coordinates voltage-reduction tests with participating transmission owners. These tests occur on the distribution system and are conducted in accordance with Operating Procedure No. 13 (OP 13), *Standards for Voltage Reduction and Load-Shedding Capability.* With the validated results, ISO-NE does not anticipate any voltage concerns for the winter capacity period because transmission reactive resources and generator reactive capabilities will be monitored and controlled for safe and reliable operation on the bulk power system.

Zonal Load Forecasting

New England continues to utilize the Metrix Zonal load forecast which produces a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability on a zonal level by taking into account conflicting weather patterns, for example when the Boston zone is forecasted to be 5°F while the Hartford area is forecast to be 30°F. This zonal forecast ensures an accurate reliability commitment on a regional level. The loads for the eight zones are then summed to estimate a total New England load, adding an additional New England load forecast to ISO-NE’s Advanced Neural Network (ANN) models and Similar Day (SimDay) analyses.

Natural Gas Supply

While natural gas continues to be the predominant fuel source in New England to produce electricity, ISO-NE continues to monitor factors affecting the deliverability of natural gas throughout the winter reliability assessment period. ISO-NE has reviewed natural gas pipeline maintenance schedules and determined that they should have no adverse impact on gas availability for the 2015-16 assessment period. However it does anticipate the potential for various amounts of single-fuel, gas-only power plants to be temporarily unavailable during cold or extreme winter weather conditions or during force majeure conditions on the regional gas infrastructure. As such, New England forecasts approximately 4,200 MW of natural-gas-fired capacity may be at risk for this winter period. To determine sufficient operable capacity margins, the ISO-NE’s long- and short-term outage coordination evaluates and accounts for at-risk gas-fired generation. As needed, ISO-NE would balance the mitigation of these scenarios with real-time supplemental commitment and the use of emergency procedures.

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To improve situational awareness, ISO-NE has developed a gas-utilization tool (GUT) that assists control room operators in measuring the at-risk gas capacity and evaluating current-day and next-day operating plans. The tool uses data gathered from electronic bulletin boards (EBBs) presented by the gas pipelines serving New England. It provides visibility and awareness of general pipeline conditions and allows for estimating scheduled deliveries on the basis of historical nominations for local distribution companies and commercial and industrial loads. The results offer an estimation of the remaining natural gas pipeline capacity available for use by the New England power sector and a forecast of natural gas capacity at risk.

The 2014-15 Winter Reliability program proved to be a success. ISO-NE expects that the FERC approved 2015–16 Winter Reliability Program (ER15-2208-000 Winter Reliability Program – ISO New England) will continue to address several challenges that could have an adverse impact on generation during the 2015–16 winter period. Similar to last year’s program, the 2015–16 Winter Reliability Program and other supportive programs provide incentives that include the following components:

- A winter demand-response program that may be called on 30 times during winter 2015-16
- A dual-fuel commissioning program that will compensate units for some of the costs associated with dual-fuel commissioning to provide an incentive for creating more dual-fuel facilities in New England
- A dual-fuel testing program that will compensate units for some of the costs associated with the fuel-swap testing to ensure a smooth fuel swap during the winter period
- An incentive program to store fuel oil on site before the start of winter.
- An incentive program to contract for liquefied natural gas (LNG) for New England resources before the winter

During the 2015-16 winter period, ISO-NE plans to regularly participate in NPCC conference calls to share information on current and forecasted operating conditions. It also will continue to work with the regional natural gas industry to further improve the coordination and communication of planned and unplanned outages and convey real-time operating conditions that promote the reliability of the bulk electric system, which is made possible through FERC Order 787.

ISO-NE has several procedures that can also be invoked to mitigate regional fuel-supply emergencies adversely affecting the power generation sector:

1. Operating Procedure No. 4, Action During a Capacity Deficiency establishes criteria and guidelines for actions during capacity deficiencies resulting from
generator and transmission contingencies and prescribes actions to manage operating reserve requirements.\(^7\)

2. Operating Procedure No. 7 (OP 7), *Action in an Emergency*, establishes criteria to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or any other emergency ISO-NE deems needing resolution through an appropriate action in an isolated or widespread area of New England.\(^8\)

3. Operating Procedure No. 21 (OP 21), *Energy Inventory Accounting and Action During an Energy Emergency*, helps mitigate the adverse impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel-supply deficiencies that can occur anytime.\(^9\) Fuel-supply deficiencies are the temporary or prolonged disruption to regional fuel-supply chains for coal, natural gas, LNG, and heavy and light fuel oil.

**New York**

*Operational Readiness*

The New York Independent System Operation (NYISO), as the sole Balancing Authority for the New York Control Area (NYCA), anticipates adequate capacity exists to meet the New York State Reliability Council’s (NYSRC) Installed Reserve Margin (IRM) of 17 percent for the 2015-16 winter season. The IRM is unchanged from the previous year.

The weather-normalized 2014-15 winter peak was 24,500 MW, 237 MW (0.96 percent) less than the forecast of 24,737 MW prepared in December 2013. The current 2015-16 peak forecast is 24,515 MW and was updated in December, 2014. It is lower than the December 2013 forecast by 222 MW (0.90 percent) and 133 MW (0.54 percent) less than the actual winter peak in 2014-15 of 24,648 MW. This forecast load is 4.24 percent lower than the all-time winter peak load of 25,738 set in winter 2013-14 on January 7, 2014.

There are two higher-than-expected scenarios forecast. One is a forecast without the impacts of energy efficiency programs. The second is a forecast based on extreme

\(^7\) Operating Procedure No. 4 is located on the ISO’s web site at: [http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf](http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf)

\(^8\) Operating Procedure No. 7 is located on the ISO’s web site at: [http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf](http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf)

weather conditions, set to the 90th percentile of typical peak-producing weather conditions. These are 24,738 MW and 26,097 MW respectively.

The decline in forecasted peak demand is attributed primarily to the impacts of energy efficiency and conservation as well as recent industrial load curtailment in an upstate zone. The energy efficiency forecast is based on historic implementation rates and a projection of future Energy Efficiency investments that are expected to occur, based on future Energy Efficiency budget values provided by the New York State Public Service Commission (NYSPSC).

No unique operational problems were observed from NYISO capability assessment studies. The NYISO maintains Joint Operating Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement, or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas if required. Prior to the operating month, the NYISO communicates to neighboring control areas both the capacity-backed import and export transactions that are expected for the NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2015-16 winter season the New York Balancing Authority expects to have 338 MW of net import capacity available.

The NYISO anticipates sufficient resources to meet peak demand without the need to resort to emergency operations. The Emergency Demand Response Program (EDRP) and ICAP/Special Case Resource program (ICAP/SCR) are designed to promote participation and the expectation is for full participation. Further control actions are outlined in NYISO policies and procedures. There is no limitation as to the number of times a resource can be called upon to provide response. Special Case Resources are required to respond when notice has been provided in accordance with NYISO’s procedures; response from EDRP is voluntary for all events.

Winter Readiness

The NYISO Market Mitigation and Analysis Department performed on-site visits of several generating stations (sum 14,901 MW) to discuss past winter operations and preparations for winter 2015-16. Their visits focused on units with low capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, causes of failed starts, programs to improve performance, and programs in place to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel switching capabilities to improve winter operations.

In the winter of 2013-14 the NYISO instituted a Cold Weather Survey. This survey is sent to all generators and assesses their primary and secondary fuel inventories. This survey is sent prior to the winter season to get baseline numbers and then on a weekly basis.
In addition, the survey is sent on days in which extreme temperatures are forecast, in order to enhance real-time situational awareness. The survey allows operators to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day. This procedure will be in place for winter 2015-16. In addition, enhanced Operator visualization of the gas system will be in place in the NYISO Control Center. The NYISO continues to work on improving gas-electric coordination to enhance reliability and availability of gas fueled units in the future, and is also considering potential market changes to provide incentives to generators to maintain alternate fuel availability.

Ontario

Base Load

Ontario expects conditions for surplus baseload generation (SBG) to continue during the assessment period. It is expected that SBG will be managed effectively via normal market mechanisms including intertie scheduling, nuclear manoeuvring or shutdown and the dispatch of grid-connected renewable resources.

Voltage Control

Ontario does not foresee any voltage management issues this winter season. However, as high voltage situations arise during periods of light load, the removal of at least one 500 kV circuit may be required to help reduce voltages. Planning procedures are in place to ensure adequate voltage control devices are available during outage conditions when voltage control conditions are more acute.

Operating Procedures

Ontario expects to have sufficient electricity to meet its forecasted demand. To prepare for the peak seasons, the IESO meets with gas pipeline operators every six months to discuss gas supply and planned maintenance on the gas and electric systems. As of November 2015, it has been determined that the current natural gas storage level in Ontario is at the five year average. Since winter 2014-15, the IESO has formalized a Seasonal Readiness program that exercises units which have been offline for a significant length of time to ensure their readiness for peak periods.

For future improvements, the IESO continues to work on enhancing existing communication protocols with gas pipeline and distribution system operators to facilitate information sharing. There is currently a stakeholder engagement initiative (Gas-Electric Coordination Enhancements) underway to seek input on proposed enhancements to the communication and coordination efforts.
Québec

Reservoir Levels

Hydro conditions for this upcoming winter peak period are such that reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the winter.

Coordination

No significant issues concerning neighboring areas that could impact operations in the Québec Area have been identified. However, during very cold weather periods, NPCC areas will discuss and coordinate planned interchange schedules and conference calls will be held as needed in this context.

Extreme load weather and extreme temperatures

Extreme cold weather results in a large load pickup over the normal demand forecast. This situation is addressed at the planning stage through TransÉnergie’s Transmission Design Criteria. When designing the system, one particular criterion edicts that both steady state and stability assessments be made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast. This is equivalent to 110 percent of peak winter demand. This ensures that the system is designed to carry the resulting transfers while conforming to all design criteria. Resources needed to feed the load during such episodes must be planned and provided by Hydro-Québec Distribution, the Load Serving Entity.

On an operations horizon, if peak demands are higher than expected a number of measures are available to the System Control personnel. Operating Instruction I-001 lists such measures:

- Limitations on non-guaranteed wheel through and export transactions
- Operation of hydro generating units at their near-maximum output (away from optimal efficiency, but still allowing for reserves)
- Use of import contracts with neighbouring systems
- Use of interruptible load programs
- Reducing 30-minute reserve and stability reserve
- Applying voltage reduction
- Making public appeals
• Ultimately using cyclic load shedding to re-establish reserves

Most of the Québec’s area hydro generators are located in the north of the province, where extremely cold ambient temperatures often occur during winter periods. Specific Design requirements are implemented to ensure that extreme ambient temperature does not affect operations. In case of any issues that might arise in real time, Maintenance Notices are issued to operators to handle such concerns.

Voltage control

Voltage support in the southern part of the system (load area) might be a concern during Winter Operating Periods especially during episodes of heavy load. Hydro-Québec Production (the largest producer on the system) ensures that maintenance on generating units is finished by December 1, and that all possible generation is available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power.

Voltage variations on the high voltage transmission system are also of some concern. These are normal variations due to changes in transmitted power from North to South during load pickup and interconnection ramping. In this situation, the system has to meet a specific Transmission Design Criterion concerning voltage variations on the system. This criterion quantifies acceptable voltage variations due to load pickup and/or interconnection ramping. All planning and operating studies must now conform to this criterion.
7. Post-Seasonal Assessment and Historical Review

Winter 2014-15 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator area’s winter 2014-15 operational experiences.

The NPCC coincident peak of 108,092 MW occurred on January 8, 2015 HE18 EST.

Maritimes

The Maritimes system demand during the NPCC coincident peak was 5,280 MW. Maritimes actual peak was 5,314 MW on February 24, 2015 at HE7 EST.

All major transmission and interconnections were in service.

New England

The actual peak demand of 20,583 MW occurred January 8, 2015, hour ending (HE) 18 Eastern Standard Time (EST) with the forecasted normal peak demand for winter 2014-15 of 21,086 MW. This peak had occurred during the NPCC coincident peak week.

M/LCC 2, Abnormal Conditions Alert, and OP 4, Action during a Capacity Deficiency, needed to be implemented on Saturday, December 4, 2014, to manage 30-minute operating reserve requirements. This implementation was attributable to the curtailment of peak-hour interchanges of more than 2,000 MW from what was forecast of neighboring systems due to the loss of two major 735 kV transmission lines in Québec. The initial near-term load forecast for the peak hour was 18,200 MW, 204 MW more than the actual peak demand of 17,996 MW.

New York

The actual peak demand of 24,648 MW occurred January 7, 2015 HE19 EST. This was a new all time winter peak load for New York. During the NPCC coincident peak week, the New York demand was 24,327 MW.

No transmission or reactive capability issues experienced during the 2014-15 operating period and firm load shedding was not required with no emergency procedures utilized.
**Ontario**

The actual peak demand was 21,814 MW on January 7, 2015 HE18 EST. During the NPCC coincident peak week, the Ontario demand was 20,999 MW. January and February were both colder than normal months but their peaks were significantly impacted by the Industrial Conservation Initiative (ICI). Wholesale customers’ consumption showed continued weakness from the last quarter of 2014 and marked five consecutive months of contraction into 2015.

No significant events impacting the reliability of the transmission system occurred during the winter 2014-2015 operating period.

**Québec**

The internal demand forecast was 37,985 MW for the 2014-15 winter operating period. During the NPCC coincident peak week, the Québec demand was 36,903 MW and the actual peak demand of 38,950 MW occurred on January 8, 2015 at 07h21 EST. The difference between the forecasted and the actual demand is due to the temperature colder than expected. Temperature in Montréal at peak was -24°C (-11.2°F); 9°C (16°F) below normal and wind velocity was 19 km/h (11.8 mph).

At that time, net imports of 1,436 MW were sustained by the Québec Balancing Authority. Moreover, 979 MW of interruptible industrial load was called for the peak hour. Wind Power Plants were generating 978 MW, 34 percent of the wind nameplate capacity which is close of the assumption used in this assessment (29 percent of total wind capacity during the winter peak period). On January 8, appeal to the public was not needed.

The actual peak demand for the winter 2014-15 (38,950 MW) was lower than the historical peak demand of 39,240 MW that occurred during the 2013-14 winter operating period.
Historical Winter Demand Review (Pre-2015-16)

The table below summarizes historical non-coincident winter peaks for each NPCC Balancing Authority Area over the last ten years.

Table 10: Ten Year Historical Winter Peak Demands (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
<th>Québec</th>
<th>NPCC Non-Coincident</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006-07</td>
<td>5,493</td>
<td>21,640</td>
<td>25,057</td>
<td>23,935</td>
<td>36,251</td>
<td>112,376</td>
</tr>
<tr>
<td>2007-08</td>
<td>5,385</td>
<td>21,782</td>
<td>25,021</td>
<td>23,054</td>
<td>35,352</td>
<td>110,594</td>
</tr>
<tr>
<td>2008-09</td>
<td>5,504</td>
<td>21,026</td>
<td>24,673</td>
<td>22,983</td>
<td>37,230</td>
<td>111,416</td>
</tr>
<tr>
<td>2009-10</td>
<td>5,205</td>
<td>20,791</td>
<td>24,074</td>
<td>22,045</td>
<td>34,659</td>
<td>106,774</td>
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<tr>
<td>2010-11</td>
<td>5,252</td>
<td>21,495</td>
<td>24,654</td>
<td>22,733</td>
<td>37,717</td>
<td>111,851</td>
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<tr>
<td>2011-12</td>
<td>4,963</td>
<td>19,926</td>
<td>23,901</td>
<td>21,649</td>
<td>35,481</td>
<td>105,920</td>
</tr>
<tr>
<td>2012-13</td>
<td>5,431</td>
<td>20,877</td>
<td>24,658</td>
<td>22,610</td>
<td>38,797</td>
<td>112,373</td>
</tr>
<tr>
<td>2013-14</td>
<td>5,467</td>
<td>21,453</td>
<td>25,738</td>
<td>22,774</td>
<td>39,240</td>
<td>114,672</td>
</tr>
<tr>
<td>2014-15</td>
<td>5,314</td>
<td>20,583</td>
<td>24,648</td>
<td>21,814</td>
<td>38,950</td>
<td>111,309</td>
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<tr>
<td>2015-16 Forecast</td>
<td>5,509</td>
<td>21,077</td>
<td>24,515</td>
<td>22,389</td>
<td>38,192</td>
<td>111,682</td>
</tr>
</tbody>
</table>

*Note: Values highlighted are record demand values that occurred during the NPCC winter capacity period.*
8. **2015-16 Winter Reliability Assessments of Adjacent Regions**

For a comprehensive review of the Reliability First Corporation Seasonal Resource, Demand and Transmission Assessment, go to:

https://www.rfirst.org/reliability/Pages/ReliabilityReports.aspx
9. CP-8 2015-16 Winter Multi-Area Probabilistic Reliability Assessment

Executive Summary

Please refer to Appendix VIII- CP-8 2015-16 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation for the full CP-8 Report, including the Executive Summary.
## Appendix I – Winter 2015-16 Normal Load and Capacity Forecasts

### Table AP-1 - NPCC Summary

<table>
<thead>
<tr>
<th>Area</th>
<th>NPCC</th>
<th>Revision Date</th>
<th>11/17/14</th>
</tr>
</thead>
</table>

### Control Area Load and Capacity

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<tr>
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</thead>
<tbody>
<tr>
<td>22-Nov-15</td>
<td>163,016</td>
<td>-696</td>
<td>162,320</td>
<td>96,333</td>
<td>4,366</td>
<td>25,512</td>
<td>8,852</td>
<td>11,513</td>
<td>37,025</td>
<td>24,476</td>
<td>25.4%</td>
<td>21,300</td>
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<td>163,876</td>
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<td>750</td>
<td>163,876</td>
<td>103,601</td>
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<td>21,319</td>
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<td>163,876</td>
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<td>18,768</td>
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<td>16,977</td>
<td>8,852</td>
<td>14,603</td>
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<td>14,653</td>
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<td>4,419</td>
<td>16,654</td>
<td>8,852</td>
<td>14,592</td>
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<td>110,097</td>
<td>4,425</td>
<td>16,680</td>
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<td>14,515</td>
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<td>17.0%</td>
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<td>820</td>
<td>164,452</td>
<td>106,506</td>
<td>4,412</td>
<td>16,972</td>
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<td>14,976</td>
<td>31,948</td>
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<td>820</td>
<td>164,452</td>
<td>106,149</td>
<td>4,410</td>
<td>16,644</td>
<td>8,852</td>
<td>14,779</td>
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<td>164,452</td>
<td>103,076</td>
<td>4,411</td>
<td>16,725</td>
<td>8,852</td>
<td>14,629</td>
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<td>101,840</td>
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<td>16,156</td>
<td>8,852</td>
<td>14,477</td>
<td>30,632</td>
<td>27,551</td>
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<td>520</td>
<td>163,779</td>
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<td>21,231</td>
<td>8,852</td>
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<td>21,067</td>
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<td>31,617</td>
<td>33,907</td>
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<td>30,341</td>
<td>34.2%</td>
</tr>
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</table>

### Notes

1. Net Interchange represents purchases and sales with Areas outside of NPCC
2. Total Capacity = Installed Capacity + Net Interchange
3. Net Margin = Total Capacity - Load Forecast - Interruptible Load - Known maintenance - Operating reserve - Unplanned Outages
4. Revised Net Margin = Net Margin - Bottled resources
## Table AP-2 – Maritimes

**Control Area Load and Capacity**

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Normal Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
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</thead>
<tbody>
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<td>7744</td>
<td>4489</td>
<td>318</td>
<td>930</td>
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<td>279</td>
<td>1005</td>
<td>37.1%</td>
</tr>
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<td>7744</td>
<td>-200</td>
<td>7544</td>
<td>4674</td>
<td>244</td>
<td>960</td>
<td>693</td>
<td>279</td>
<td>1182</td>
<td>25.3%</td>
</tr>
<tr>
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<td>7544</td>
<td>4769</td>
<td>241</td>
<td>967</td>
<td>693</td>
<td>279</td>
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</tr>
<tr>
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<td>-200</td>
<td>7544</td>
<td>4844</td>
<td>242</td>
<td>967</td>
<td>693</td>
<td>279</td>
<td>1003</td>
<td>20.7%</td>
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<tr>
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<td>4939</td>
<td>236</td>
<td>967</td>
<td>693</td>
<td>279</td>
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</tr>
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<td>7544</td>
<td>4979</td>
<td>291</td>
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<td>7588</td>
<td>5230</td>
<td>237</td>
<td>971</td>
<td>693</td>
<td>279</td>
<td>652</td>
<td>12.5%</td>
</tr>
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<td>-200</td>
<td>7588</td>
<td>5164</td>
<td>241</td>
<td>971</td>
<td>693</td>
<td>279</td>
<td>722</td>
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<td>7588</td>
<td>5265</td>
<td>242</td>
<td>971</td>
<td>693</td>
<td>279</td>
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<td>7588</td>
<td>5509</td>
<td>258</td>
<td>971</td>
<td>693</td>
<td>279</td>
<td>392</td>
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<td>7592</td>
<td>5265</td>
<td>242</td>
<td>1025</td>
<td>693</td>
<td>279</td>
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<td>7592</td>
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<td>1025</td>
<td>693</td>
<td>279</td>
<td>439</td>
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<td>7592</td>
<td>5062</td>
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<td>693</td>
<td>279</td>
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<td>7592</td>
<td>4945</td>
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<td>1002</td>
<td>693</td>
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<td>279</td>
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<td>1103</td>
<td>693</td>
<td>279</td>
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<td>693</td>
<td>279</td>
<td>1631</td>
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</tbody>
</table>

**Notes**

~ Firm sale of 200 MW for all hours of December 2015 through February 2016 are forecasted.
~ Known Maint./Derate include wind derates of 75.5 percent.
## Table AP-3 – New England

### Control Area Load and Capacity

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Normal Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Extreme Unplanned Outages</th>
<th>Net Margin MW</th>
<th>Not Margin %</th>
</tr>
</thead>
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<td>4,320</td>
<td>7,500</td>
<td>2,045</td>
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</tr>
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<td>32,957</td>
<td>1,256</td>
<td>34,213</td>
<td>19,725</td>
<td>552</td>
<td>3,807</td>
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<td>5,583</td>
<td>7,300</td>
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<td>34,113</td>
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<td>552</td>
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<td>2,375</td>
<td>6,402</td>
<td>7,734</td>
<td>3,735</td>
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<td>7,838</td>
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<td>7,400</td>
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<td>7,750</td>
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<td>709</td>
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<td>389</td>
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<td>1,226</td>
<td>34,100</td>
<td>18,712</td>
<td>587</td>
<td>1,944</td>
<td>2,375</td>
<td>3,295</td>
<td>4,805</td>
<td>8,361</td>
<td>44.7%</td>
</tr>
<tr>
<td>20-Mar-16</td>
<td>32,957</td>
<td>1,226</td>
<td>34,100</td>
<td>18,339</td>
<td>587</td>
<td>3,024</td>
<td>2,375</td>
<td>2,705</td>
<td>4,024</td>
<td>8,244</td>
<td>45.0%</td>
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<tr>
<td>27-Mar-16</td>
<td>32,957</td>
<td>1,226</td>
<td>34,100</td>
<td>17,762</td>
<td>587</td>
<td>4,083</td>
<td>2,375</td>
<td>2,700</td>
<td>3,742</td>
<td>7,767</td>
<td>43.7%</td>
</tr>
</tbody>
</table>

**Notes**

1. Installed Capacity based on Seasonal Claimed Capabilities, non-commercial capacity, forecasted retirements and ISO-NE Forward Capacity Market (FCM) resource obligations for the 2015-16 capacity commitment period. Derates for variable resources are reflected.
2. Net Interchange includes peak purchases / sales from Maritimes, Quebec and New York.
3. Load Forecast assumes a Peak Load Exposure of 22,740 MW, as reported in the 2015 CELT Report and does include 1,663 MW credit of Passive Demand Response.
4. Interruptible Loads consist of both Active Demand Response (413 MW) and fast-start FCM Demand Resource (174 MW) obligations.
5. Includes known scheduled maintenance as of October 23, 2015.
6. 2,375 MW operating reserve assumes 125% of the largest contingency of 1,400 MW and 50% of the second largest contingency of 1,250 MW.
7. Assumed unplanned outages based on historical observation of winter outages and additional outages for generation at risk due to gas supply. Scheduled generator outages with natural or LNG gas identified as the primary fuel source will credit the gas at risk MW value.
8. Includes a normal forecasted unplanned outage allotment and gas at risk value (from 525 MW to 4,254 MW)
**Table AP-4 – New York**

**Control Area Load and Capacity**

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Reg. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
</tr>
</thead>
<tbody>
<tr>
<td>22-Nov-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>22,546</td>
<td>963</td>
<td>4,494</td>
<td>2,620</td>
<td>4,282</td>
<td>8.743</td>
<td>38.8%</td>
</tr>
<tr>
<td>26-Nov-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>22,797</td>
<td>963</td>
<td>4,434</td>
<td>2,620</td>
<td>4,294</td>
<td>8.633</td>
<td>37.9%</td>
</tr>
<tr>
<td>6-Dec-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>23,973</td>
<td>963</td>
<td>4,511</td>
<td>2,620</td>
<td>4,281</td>
<td>7.303</td>
<td>36.5%</td>
</tr>
<tr>
<td>13-Dec-15</td>
<td>41,387</td>
<td>338</td>
<td>41,725</td>
<td>24,515</td>
<td>963</td>
<td>3,976</td>
<td>2,620</td>
<td>4,324</td>
<td>7.253</td>
<td>26.6%</td>
</tr>
<tr>
<td>20-Dec-15</td>
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<td>338</td>
<td>41,725</td>
<td>24,126</td>
<td>963</td>
<td>3,566</td>
<td>2,620</td>
<td>4,355</td>
<td>8.001</td>
<td>33.2%</td>
</tr>
<tr>
<td>27-Dec-15</td>
<td>41,312</td>
<td>338</td>
<td>41,650</td>
<td>23,612</td>
<td>963</td>
<td>3,543</td>
<td>2,620</td>
<td>4,359</td>
<td>8.479</td>
<td>35.9%</td>
</tr>
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<td>3-Jan-16</td>
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<td>338</td>
<td>41,650</td>
<td>23,902</td>
<td>963</td>
<td>3,421</td>
<td>2,620</td>
<td>4,369</td>
<td>8.301</td>
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</tr>
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<td>10-Jan-16</td>
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<td>338</td>
<td>41,650</td>
<td>24,134</td>
<td>963</td>
<td>3,280</td>
<td>2,620</td>
<td>4,379</td>
<td>8.184</td>
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<td>338</td>
<td>41,650</td>
<td>23,784</td>
<td>963</td>
<td>3,260</td>
<td>2,620</td>
<td>4,382</td>
<td>8.567</td>
<td>36.0%</td>
</tr>
<tr>
<td>24-Jan-16</td>
<td>41,312</td>
<td>338</td>
<td>41,650</td>
<td>24,185</td>
<td>963</td>
<td>3,232</td>
<td>2,620</td>
<td>4,384</td>
<td>8.192</td>
<td>33.9%</td>
</tr>
<tr>
<td>31-Jan-16</td>
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<td>338</td>
<td>41,650</td>
<td>23,990</td>
<td>963</td>
<td>3,360</td>
<td>2,620</td>
<td>4,374</td>
<td>8.269</td>
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</tr>
<tr>
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<td>338</td>
<td>41,650</td>
<td>23,886</td>
<td>963</td>
<td>3,363</td>
<td>2,620</td>
<td>4,373</td>
<td>8.371</td>
<td>35.0%</td>
</tr>
<tr>
<td>14-Feb-16</td>
<td>41,312</td>
<td>338</td>
<td>41,650</td>
<td>23,313</td>
<td>963</td>
<td>3,366</td>
<td>2,620</td>
<td>4,373</td>
<td>8.941</td>
<td>38.4%</td>
</tr>
<tr>
<td>21-Feb-16</td>
<td>41,312</td>
<td>338</td>
<td>41,650</td>
<td>23,333</td>
<td>963</td>
<td>3,066</td>
<td>2,620</td>
<td>4,396</td>
<td>9.206</td>
<td>36.5%</td>
</tr>
<tr>
<td>28-Feb-16</td>
<td>40,937</td>
<td>338</td>
<td>41,275</td>
<td>23,427</td>
<td>963</td>
<td>3,267</td>
<td>2,620</td>
<td>4,382</td>
<td>8.582</td>
<td>36.6%</td>
</tr>
<tr>
<td>6-Mar-16</td>
<td>40,937</td>
<td>338</td>
<td>41,275</td>
<td>22,571</td>
<td>963</td>
<td>5,041</td>
<td>2,620</td>
<td>4,266</td>
<td>7.790</td>
<td>34.5%</td>
</tr>
<tr>
<td>13-Mar-16</td>
<td>40,937</td>
<td>338</td>
<td>41,275</td>
<td>21,515</td>
<td>963</td>
<td>4,384</td>
<td>2,620</td>
<td>4,251</td>
<td>9.458</td>
<td>44.0%</td>
</tr>
<tr>
<td>20-Mar-16</td>
<td>40,937</td>
<td>338</td>
<td>41,275</td>
<td>21,481</td>
<td>963</td>
<td>4,720</td>
<td>2,620</td>
<td>4,234</td>
<td>9.183</td>
<td>42.7%</td>
</tr>
<tr>
<td>27-Mar-16</td>
<td>40,937</td>
<td>338</td>
<td>41,275</td>
<td>21,013</td>
<td>963</td>
<td>4,728</td>
<td>2,020</td>
<td>4,233</td>
<td>9.644</td>
<td>45.9%</td>
</tr>
</tbody>
</table>

**Notes**

1) - Figures reflect the use of Unforced Capacity Deliverability Rights (UDRs) as currently known. UDRs represent controllable transmission projects that provide a transmission interface into NYCA. For more information on the use of UDRs, please see section 4.14 of the ICAP Manual.

2) - Negative Net Purchases and Sales values represent higher total Sales out of NYCA than total Purchases into NYCA. All purchase and sale transactions will flow through NYISO does not utilize the firm concept. All import and export transactions are finalized in Real Time Dispatch. Although LSEs may have firm contracts with external suppliers all bids must clear economically and for reliability in day ahead scheduling and real time dispatch.

4) - Values are projected as of Sept. 30, 2015 and are subject to change.

5) - Derates for variable resources, including wind, are included under “Known Maint./Derat. MW”
### Table AP-5 – Ontario

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<thead>
<tr>
<th>Area</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revision Date</td>
<td>10/28/15</td>
</tr>
</tbody>
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**Control Area Load and Capacity**

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
</tr>
</thead>
<tbody>
<tr>
<td>22-Nov-15</td>
<td>35,548</td>
<td>0</td>
<td>35,648</td>
<td>20,306</td>
<td>721</td>
<td>9,041</td>
<td>1,664</td>
<td>1,124</td>
<td>4,234</td>
<td>20.9%</td>
</tr>
<tr>
<td>29-Nov-15</td>
<td>35,548</td>
<td>-500</td>
<td>35,148</td>
<td>20,755</td>
<td>721</td>
<td>8,675</td>
<td>1,664</td>
<td>1,141</td>
<td>3,239</td>
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<tr>
<td>6-Dec-15</td>
<td>35,748</td>
<td>-500</td>
<td>35,248</td>
<td>21,041</td>
<td>721</td>
<td>8,520</td>
<td>1,664</td>
<td>1,063</td>
<td>3,261</td>
<td>15.5%</td>
</tr>
<tr>
<td>13-Dec-15</td>
<td>35,748</td>
<td>-500</td>
<td>35,248</td>
<td>20,725</td>
<td>721</td>
<td>7,900</td>
<td>1,664</td>
<td>1,018</td>
<td>4,062</td>
<td>18.6%</td>
</tr>
<tr>
<td>20-Dec-15</td>
<td>35,748</td>
<td>-500</td>
<td>35,248</td>
<td>20,436</td>
<td>721</td>
<td>7,015</td>
<td>1,664</td>
<td>1,290</td>
<td>5,564</td>
<td>27.2%</td>
</tr>
<tr>
<td>27-Dec-15</td>
<td>35,748</td>
<td>-500</td>
<td>35,248</td>
<td>20,720</td>
<td>721</td>
<td>7,043</td>
<td>1,664</td>
<td>1,456</td>
<td>5,086</td>
<td>24.5%</td>
</tr>
<tr>
<td>3-Jan-16</td>
<td>36,276</td>
<td>-500</td>
<td>35,775</td>
<td>22,388</td>
<td>565</td>
<td>7,075</td>
<td>1,664</td>
<td>1,498</td>
<td>3,705</td>
<td>16.6%</td>
</tr>
<tr>
<td>10-Jan-16</td>
<td>36,276</td>
<td>-500</td>
<td>35,775</td>
<td>21,550</td>
<td>721</td>
<td>7,896</td>
<td>1,664</td>
<td>1,475</td>
<td>3,812</td>
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</tr>
<tr>
<td>17-Jan-16</td>
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<td>-500</td>
<td>35,775</td>
<td>21,806</td>
<td>721</td>
<td>7,864</td>
<td>1,664</td>
<td>1,411</td>
<td>3,749</td>
<td>17.2%</td>
</tr>
<tr>
<td>24-Jan-16</td>
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<td>-500</td>
<td>35,775</td>
<td>21,815</td>
<td>721</td>
<td>7,881</td>
<td>1,664</td>
<td>1,332</td>
<td>3,805</td>
<td>17.4%</td>
</tr>
<tr>
<td>31-Jan-16</td>
<td>36,276</td>
<td>-500</td>
<td>35,775</td>
<td>20,976</td>
<td>721</td>
<td>7,937</td>
<td>1,664</td>
<td>1,662</td>
<td>4,259</td>
<td>20.3%</td>
</tr>
<tr>
<td>7-Feb-16</td>
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<td>-500</td>
<td>35,775</td>
<td>20,372</td>
<td>721</td>
<td>7,393</td>
<td>1,664</td>
<td>1,563</td>
<td>5,505</td>
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<td>-500</td>
<td>35,775</td>
<td>20,299</td>
<td>721</td>
<td>7,414</td>
<td>1,664</td>
<td>1,509</td>
<td>5,611</td>
<td>27.6%</td>
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<tr>
<td>21-Feb-16</td>
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<td>-500</td>
<td>35,775</td>
<td>20,258</td>
<td>721</td>
<td>7,385</td>
<td>1,664</td>
<td>1,429</td>
<td>5,701</td>
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<tr>
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<td>-500</td>
<td>35,775</td>
<td>19,901</td>
<td>721</td>
<td>8,380</td>
<td>1,664</td>
<td>1,210</td>
<td>5,330</td>
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<tr>
<td>6-Mar-16</td>
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<td>-500</td>
<td>35,775</td>
<td>19,493</td>
<td>721</td>
<td>8,460</td>
<td>1,664</td>
<td>1,299</td>
<td>5,581</td>
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<td>9,059</td>
<td>1,664</td>
<td>1,215</td>
<td>6,251</td>
<td>34.1%</td>
</tr>
<tr>
<td>20-Mar-16</td>
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<td>-500</td>
<td>35,775</td>
<td>18,394</td>
<td>721</td>
<td>9,054</td>
<td>1,664</td>
<td>1,184</td>
<td>6,201</td>
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<td>27-Mar-16</td>
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<td>-500</td>
<td>35,775</td>
<td>18,297</td>
<td>721</td>
<td>10,810</td>
<td>1,664</td>
<td>1,067</td>
<td>4,859</td>
<td>26.6%</td>
</tr>
</tbody>
</table>

**Notes**

"Installed Capacity" includes all generation registered in the IESO-administered market.

"Load Forecast" represents the normal weather case, weekly 60-minute peaks.

"Known Maint./Derat/Bottled Cap." includes the planned outages, deratings, historic hydroelectric reductions, variable generation reductions, such as allowances for capacity.

"Unplanned Outages" is based on the average amount of generation in forced outage for the assessment period.
Table AP-6 – Québec

<table>
<thead>
<tr>
<th>Area</th>
<th>Québec</th>
</tr>
</thead>
<tbody>
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Control Area Load and Capacity

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Demand Response MW</th>
<th>Known Maint./Dorat. MW</th>
<th>Reg. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
</tr>
</thead>
<tbody>
<tr>
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<td>-2,003</td>
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<td>1,699</td>
<td>4,487</td>
<td>1,600</td>
<td>1,500</td>
<td>7,783</td>
<td>26.0%</td>
</tr>
<tr>
<td>29-Nov-15</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>32,394</td>
<td>1,699</td>
<td>4,406</td>
<td>1,500</td>
<td>1,500</td>
<td>7,435</td>
<td>23.0%</td>
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<tr>
<td>6-Dec-15</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>33,867</td>
<td>1,699</td>
<td>4,068</td>
<td>1,500</td>
<td>1,500</td>
<td>6,300</td>
<td>16.6%</td>
</tr>
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<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>34,922</td>
<td>1,699</td>
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<td>1,500</td>
<td>1,500</td>
<td>5,443</td>
<td>15.6%</td>
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<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>34,881</td>
<td>1,699</td>
<td>3,970</td>
<td>1,500</td>
<td>1,500</td>
<td>5,004</td>
<td>15.5%</td>
</tr>
<tr>
<td>27-Dec-15</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>34,945</td>
<td>1,699</td>
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<td>1,500</td>
<td>1,500</td>
<td>5,263</td>
<td>15.1%</td>
</tr>
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<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>36,630</td>
<td>1,699</td>
<td>3,720</td>
<td>1,500</td>
<td>1,500</td>
<td>3,885</td>
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<td>45,336</td>
<td>37,034</td>
<td>1,699</td>
<td>3,780</td>
<td>1,500</td>
<td>1,500</td>
<td>2,821</td>
<td>7.5%</td>
</tr>
<tr>
<td>17-Jan-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>38,192</td>
<td>1,699</td>
<td>3,917</td>
<td>1,500</td>
<td>1,500</td>
<td>2,128</td>
<td>5.6%</td>
</tr>
<tr>
<td>24-Jan-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>37,511</td>
<td>1,699</td>
<td>3,952</td>
<td>1,500</td>
<td>1,500</td>
<td>2,772</td>
<td>7.4%</td>
</tr>
<tr>
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<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>35,425</td>
<td>1,699</td>
<td>4,002</td>
<td>1,500</td>
<td>1,500</td>
<td>4,803</td>
<td>13.6%</td>
</tr>
<tr>
<td>7-Feb-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>34,918</td>
<td>1,699</td>
<td>4,069</td>
<td>1,500</td>
<td>1,500</td>
<td>5,248</td>
<td>15.0%</td>
</tr>
<tr>
<td>14-Feb-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>33,855</td>
<td>1,699</td>
<td>4,211</td>
<td>1,500</td>
<td>1,500</td>
<td>6,169</td>
<td>18.2%</td>
</tr>
<tr>
<td>21-Feb-16</td>
<td>45,380</td>
<td>-44</td>
<td>45,336</td>
<td>33,024</td>
<td>1,699</td>
<td>4,290</td>
<td>1,500</td>
<td>1,500</td>
<td>6,921</td>
<td>21.0%</td>
</tr>
<tr>
<td>28-Feb-16</td>
<td>45,380</td>
<td>-544</td>
<td>44,836</td>
<td>32,595</td>
<td>1,699</td>
<td>4,331</td>
<td>1,500</td>
<td>1,500</td>
<td>8,089</td>
<td>20.9%</td>
</tr>
<tr>
<td>6-Mar-16</td>
<td>45,380</td>
<td>-544</td>
<td>44,836</td>
<td>31,902</td>
<td>1,699</td>
<td>4,538</td>
<td>1,500</td>
<td>1,500</td>
<td>7,295</td>
<td>22.9%</td>
</tr>
<tr>
<td>13-Mar-16</td>
<td>45,380</td>
<td>-544</td>
<td>44,836</td>
<td>30,923</td>
<td>1,699</td>
<td>4,577</td>
<td>1,500</td>
<td>1,500</td>
<td>8,235</td>
<td>26.6%</td>
</tr>
<tr>
<td>20-Mar-16</td>
<td>45,380</td>
<td>-544</td>
<td>44,836</td>
<td>29,444</td>
<td>1,699</td>
<td>4,753</td>
<td>1,500</td>
<td>1,500</td>
<td>9,523</td>
<td>32.4%</td>
</tr>
<tr>
<td>27-Mar-16</td>
<td>45,380</td>
<td>-544</td>
<td>44,836</td>
<td>27,295</td>
<td>1,699</td>
<td>4,808</td>
<td>1,500</td>
<td>1,500</td>
<td>11,832</td>
<td>43.3%</td>
</tr>
</tbody>
</table>

Notes

1) Includes Independent Power Producers (IPPs) and available capacity of Churchill Falls at the Newfoundland - Québec border.
2) Includes firm sale of 145 MW to Cornwall.
3) Includes 250 MW of load management through voltage reduction (Direct Control Load Management).
4) Includes 2309 MW (7%) of derated Wind capacity.
Appendix II – Load and Capacity Tables definitions

This appendix defines the terms used in the Load and Capacity tables of Appendix I. Individual Balancing Authority Area particularities are presented when necessary.

Installed Capacity

This is the generation capacity installed within a Reliability Coordinator area. This should correspond to nameplate and/or test data and may include temperature derating according to the Operating Period. It may also include wind generation derating.

Individual Reliability Coordinator area particularities

Maritimes

This number is the maximum net rating for each generation facility (net of unit station service) and does not account for reductions associated with ambient temperature derating and intermittent output (e.g. hydro and/or wind).

New England

Installed capacity is based on generator seasonal claimed capabilities (SCCs) and generation anticipated to be commercial for the identified capacity period. Totals account for the capacity values for derated renewable resources.

New York

This number includes all generation resources that participate in the NYISO Installed Capacity (ICAP) market.

Ontario

This number includes all generation registered with the IESO.

Québec

Most of the Installed Capacity in the Québec Area is owned and operated by Hydro-Québec Production. The remaining capacity is provided by Churchill Falls and by private producers (hydro, wind, biomass and natural gas cogeneration).

Net Interchange

Net Interchange is the total of Net Imports – Net Exports for NPCC and each Balancing Authority Area.
Total Capacity

Total Capacity = Installed Capacity + Net Interchange.

Demand Forecast

This is the total internal demand forecast for each Reliability Coordinator area as per its normal Demand Forecast Methodology (Appendix IV)

Demand Response

Loads that are interruptible under the terms specified in a contract. These may include supply and economic interruptible loads, Demand Response Programs or market-based programs.

Known Maintenance/Derates

This is the reduction in Total Capacity caused by forecasted planned generator outages or derates and by any additional forecasted transmission outages or constraints. Other than New England, each Reliability Coordinator Area will include wind generation derating.

Individual Reliability Coordinator area particularities

Maritimes

This includes scheduled generator maintenance and ambient temperature derates. It also includes wind and hydro generation derating.

New England

Known maintenance includes all known planned outages as publically reported in the ISO-NE Annual Maintenance Schedule.

New York

This includes scheduled generator maintenance and includes all wind and other renewable generation derating.

Ontario

This includes planned generator outages, deratings, bottling, historic hydroelectric reductions and variable generation reductions.
Québec

This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include transmission constraints on the TransÉnergie system.

Required Operating Reserve

This is the minimum operating reserve on the system for each Reliability Coordinator area.

NPCC Glossary of Terms

Operating reserve: This is the sum of ten-minute and thirty-minute reserve (fully available in 10 minutes and in 30 minutes).

Individual Reliability Coordinator area particularities

Maritimes

The required operating reserve consists of 100 percent of the first-largest contingency and 50 percent of the second-largest contingency.

New England

The required operating reserve consists of 125 percent of the first largest contingency and 50 percent of the second largest contingency.

New York

The operating reserve consists of 200 percent of the largest single generator contingency.

Ontario

The required operating reserve consists of 100 percent of the first largest contingency and 50 percent of the second largest contingency.

Québec

The required operating reserve consists of 100 percent of the largest first contingency and 50 percent of the largest second contingency, including 1,000 MW of hydro synchronous reserve distributed all over the system to be used as stability and frequency support reserve.
Unplanned Outages

This is the forecasted reduction in Installed Capacity by each Reliability Coordinator area based on historical conditions used to take into account a certain probability that some capacity may be on forced outage.

Individual Reliability Coordinator area particularities

**Maritimes**

Monthly unplanned outage values have been calculated based on historical unplanned outage data.

**New England**

Monthly unplanned outage values have been calculated on the basis of historical unplanned outage data and will also include values for at-risk natural gas capacity.

**New York**

Seasonal generator unplanned outage values are calculated based on historical generator availability data and include the loss of largest generator source contingency value.

**Ontario**

This value is a historical observation of the capacity that is on forced outage at any given time.

**Québec**

This value includes a provision for frequency regulation in the Québec Balancing Authority Area, for unplanned outages and for heavy loads as determined by the system controller.
Net Margin

Net margin = Total capacity – Load forecast + Interruptible load – Known maintenance/derates – Required operating reserve – Unplanned outages

Individual Reliability Coordinator area particularities

New York

New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin. The Installed Reserve Margin requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). New York also maintains locational reserve requirements for certain regions, including New York City (Load Zone J), Long Island (Load Zone K) and the G-J Locality (Load Zones G, H, I and J are located in Southeast New York). Load serving entities in those regions must procure a certain amount of their capacity from generators within those regions.

Bottled Resources

Bottled resources = Québec Net margin + Maritimes Net margin – available transfer capacity between Québec/Maritimes and Rest of NPCC.

This is used primarily in summer. It takes into account the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC since Québec and Maritimes are winter peaking.

Revised net margin (NPCC Summary only)

Revised net margin = Net margin – Bottled resources

This is used in the NPCC assessment and follows from the Bottled Resources calculation.
Appendix III – Summary of Forecasted Winter Transfer Capabilities

The following table represents the forecasted transfer capabilities between Reliability Coordinator areas represented as Total Transfer Capabilities (TTC). It is recognized that the forecasted and actual transfer capability may differ depending on system conditions and configurations such as real-time voltage profiles, generation dispatch or operating conditions and may also account for Transmission Reliability Margin (TRM). It should be noted that real-time transfer limits may change depending on the operation of the system at the time and readers are encouraged to review information on the Available Transfer Capability (ATC) and Total Transfer Capabilities (TTC) between Reliability Coordinator areas. Transmission limit particularities can be found on the Open Access Same-Time Information Transmission System (OASIS) or Area specific website listed below.

- **Maritimes**

- **New England**

- **New York**

- **Ontario**

- **Québec**
## Transfers from Maritimes to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eel River (NB)/Matapédia (QC)</td>
<td>335</td>
<td>325</td>
<td>Eel River winter rating is 350 MW. When Eel River converter losses and line losses to the Québec border are taken into account, Eel River to Matapédia transfer is 335 MW. Eel River current limit of 325 MW is due to load loss limitation in the Maritimes.</td>
</tr>
<tr>
<td>Edmundston (NB)/Madawaska (QC)</td>
<td>435</td>
<td>320</td>
<td>Madawaska HVDC winter rating is 435 MW. Madawaska current limit of 325 MW is due to load-loss limitation in the Maritimes.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>770</strong></td>
<td><strong>525</strong></td>
<td>At the present time the NB to HQ-HVDC transfer capability is limited to 525 MW due to load loss limitations in the Maritimes. (i.e. Eel River is at 325 MW Madawaska limited to 200 MW or Madawaska at 325 MW Eel River limited to 200 MW). This limit is currently under review.</td>
</tr>
</tbody>
</table>

| New England           |          |          |          |
| Orrington, Keene Road | 1,000    | 1,000    | For resource adequacy studies, NE assumes that it can import 1,000 MW of capacity to meet New England loads with 50 MW of margin for real-time balancing control. |
| **Total**             | **1,000**| **1,000**|          |
## Transfers from New England to Interconnection Point

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maritimes</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keswick (3001 line), Point Lepreau (390/3016 line)</td>
<td>550</td>
<td>200</td>
<td>Transfer capability depends on operating conditions in northern Maine and the Maritimes area. If key generation or capacitor banks are not operational, the transfer limits from New England to New Brunswick will decrease. At present, the NBP-SO has limited the transfer to 200 MW but will increase it to 550 MW on request from the NBP-SO under emergency operating conditions for up to 30 minutes. This limitation is due to system security/stability within New Brunswick and is currently under review.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>550</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)</td>
<td>1,200</td>
<td>1,200</td>
<td>The transfer capability is dependent upon New England system load levels and generation dispatch. If key generators are online and New England system load levels are acceptable, the transfers to New York could exceed 1,200 MW. ISO-NE planning assumptions are based on an interface limit of 1,200 MW.</td>
</tr>
<tr>
<td>NNC Cable (Northport-Norwalk Harbor Cable)</td>
<td>200</td>
<td>200</td>
<td>The NNC is an interconnection between Norwalk Harbor, Connecticut and Northport, New York. The flow on the NNC Interface is controlled by the Phase Angle Regulating transformer at Northport, adjusting the flows across the cables listed. ISO New England and New York ISO Operations staff evaluates the seasonal TTC across the NNC Interface on a periodic basis or when there are significant changes to the transmission system that warrant an evaluation. A key objective while determining the TTC is to not have a negative impact on the prevalent TTC across the Northern NE-NY AC Ties Interface.</td>
</tr>
<tr>
<td>LI / Connecticut (CSC)</td>
<td>330</td>
<td>330</td>
<td>The transfer capability of the Cross Sound Cable (CSC) is 346 MW. However, losses reduce the amount of MWs that can actually be delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. The Cross Sound Cable is a DC tie and is not included in the Feasible simultaneous transfer capability with NY.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,730</td>
<td>1,730</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase II HVDC link (451 and 452 lines)</td>
<td>1,200</td>
<td>1,200</td>
<td>Export capability of the facility is 1,200 MW.</td>
</tr>
<tr>
<td>Highgate (VT) – Bedford (BDF) Line 1429</td>
<td>170</td>
<td>100</td>
<td>Capability of the tie is 225 MW but at times, conditions in Vermont limit the capability to 100 MW or less. The DOE permit is 170 MW.</td>
</tr>
<tr>
<td>Derby (VT) – Stanstead (STS) Line 1400</td>
<td>0</td>
<td>0</td>
<td>Though there is no capability scheduled to export to Québec through this interconnection path, exports may be able to be provided, dependent upon New England system load levels and generation dispatch. ISO-NE planning assumptions are based on a path limit of 0 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,370</strong></td>
<td><strong>1,300</strong></td>
<td>The New England to Québec transfer limit at peak load is assumed to be 0 MW. It should be noted that this limit is dependent on New England generation and could be increased up to approximately 350 MW depending on New England dispatch. If energy was needed in Québec and the generation could be secured in the Real-Time market, this action could be taken to increase the transfer limit.</td>
</tr>
</tbody>
</table>
## Transfers from New York to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New England</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)</td>
<td>1,600</td>
<td>1,400</td>
<td>New York applies a 200 MW Transmission Reliability Margin (TRM).</td>
</tr>
<tr>
<td>LI / Connecticut Northport-Norwalk Harbor Cable</td>
<td>200</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>LI / Connecticut Cross-Sound Cable</td>
<td>330</td>
<td>330</td>
<td>Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,130</td>
<td>1,930</td>
<td></td>
</tr>
<tr>
<td><strong>Ontario</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines PA301, PA302, BP76, PA27, L33P, L34P</td>
<td>1,900</td>
<td>1,600</td>
<td>New York applies a 300 MW Transmission Reliability Margin (TRM). Thermal limits on the QFW interface may restrict exports to lesser values when the generation in the Niagara area is taken into account.</td>
</tr>
<tr>
<td><strong>PJM</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PJM AC Ties</td>
<td>1,300</td>
<td>1,000</td>
<td>New York applies a 300 MW Transmission Reliability Margin (TRM).</td>
</tr>
<tr>
<td>NYC/PJM Linden VFT</td>
<td>315</td>
<td>315</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,615</td>
<td>1,315</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chateauguay (QC)/Massena (NY)</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>Cedards / Quebec</td>
<td>100</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,100</td>
<td>1,100</td>
<td></td>
</tr>
</tbody>
</table>
### Transfers from Ontario to Interconnection Point

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines PA301, PA302, BP76, PA27, L33P, L34P</td>
<td>1,800</td>
<td>1,600</td>
<td>The TRM is 200 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,800</td>
<td>1,600</td>
<td></td>
</tr>
<tr>
<td><strong>MISO Michigan</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines L4D, L51D, J5D, B3N</td>
<td>1,750</td>
<td>1,550</td>
<td>The TRM is 200 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,750</td>
<td>1,550</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NE / RPD – KPW Lines D4Z, H4Z</td>
<td>110</td>
<td>100</td>
<td>The 110 MW reflects an agreement through the TE-IESO Interconnection Committee. The TRM is 10 MW.</td>
</tr>
<tr>
<td>Ottawa / BRY – PGN Lines X2Y, Q4C</td>
<td>140</td>
<td>140</td>
<td>There is no capacity to export to Québec through Lines P33C and X2Y.</td>
</tr>
<tr>
<td>Ottawa / Brookfield Lines D5A, H9A</td>
<td>200</td>
<td>190</td>
<td>Only one of H9A or D5A can be in service at any time. The TRM is 10 MW.</td>
</tr>
<tr>
<td>East / Beau Lines B5D, B31L</td>
<td>470</td>
<td>470</td>
<td>Capacity from Saunders that can be synchronized to the Hydro-Québec system.</td>
</tr>
<tr>
<td>HAW / OUTA Lines A41T , A42T</td>
<td>1,250</td>
<td>1,230</td>
<td>The TRM is 20 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,170</td>
<td>2,130</td>
<td></td>
</tr>
<tr>
<td><strong>MISO Manitoba, Minnesota</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NW / MAN Lines K21W, K22W</td>
<td>300</td>
<td>275</td>
<td>The TRM is 25 MW.</td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>150</td>
<td>140</td>
<td>The TRM is 10 MW</td>
</tr>
<tr>
<td>------------------</td>
<td>-----</td>
<td>-----</td>
<td>-----------------</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>450</strong></td>
<td><strong>415</strong></td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from Québec to Interconnection Point

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matapédia (QC)/Eel River (NB)</td>
<td>350 + Radial loads</td>
<td>350 + Radial loads</td>
<td>Eel River HVDC winter rating is 350 MW plus available radial load transfers.</td>
</tr>
<tr>
<td>Madawaska (QC)/Edmundston (NB)</td>
<td>423 + radial loads</td>
<td>423 + radial loads</td>
<td>Madawaska winter rating is 435 MW. When Madawaska converter losses and line losses to the New Brunswick border are taken into account, Madawaska to St-André transfer is 423 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>773+ radial loads</strong></td>
<td><strong>773 + radial loads</strong></td>
<td>Radial load transfer amount is dependent on local loading and is updated monthly and reviewed annually.</td>
</tr>
</tbody>
</table>

## New England

<table>
<thead>
<tr>
<th>NIC / CMA HVDC link</th>
<th>2,000</th>
<th>2,000</th>
<th>Capability of the facility is 2,000 MW The value estimated at peak load is 1,400 MW.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bedford (BDF) – Highgate (VT) Line 1429</td>
<td>225</td>
<td>225</td>
<td>Capacity of the Highgate HVDC facility is 225 MW</td>
</tr>
<tr>
<td>Stanstead (STS) – Derby (VT) Line 1400</td>
<td>50</td>
<td>50</td>
<td>Normally only 35 MW of load in New England is connected.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,275</strong></td>
<td><strong>2,275</strong></td>
<td></td>
</tr>
</tbody>
</table>

## New York

<table>
<thead>
<tr>
<th>Chateauguay (QC)/Massena (NY)</th>
<th>1,800</th>
<th>1,800</th>
<th>Beauharnois G.S. is used for Québec needs under peak load conditions, in which case transfer is limited to Châteauguay capacity (1000 MW).</th>
</tr>
</thead>
<tbody>
<tr>
<td>Les Cèdres (Qc)/Dennison (NY)</td>
<td>199</td>
<td>199</td>
<td>Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 199 MW and 160 MW respectively. However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,999</strong></td>
<td><strong>1,999</strong></td>
<td></td>
</tr>
<tr>
<td>Ontario</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---------------------------------------------</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>Les Cèdres (Qc)/Cornwall (Ont.)</td>
<td>160</td>
<td>160</td>
<td></td>
</tr>
<tr>
<td>Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 199 MW and 160 MW respectively. However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beauharnois(Qc)/St-Lawrence (Ont.)</td>
<td>800</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Beauharnois G.S. is used for Québec needs under peak load conditions in which case no export is expected on this path at peak time.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brookfield/Ottawa (Ont.)</td>
<td>250</td>
<td>250</td>
<td></td>
</tr>
<tr>
<td>Only one of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rapide-des-îles (Qc)/Dymond (Ont.)</td>
<td>85</td>
<td>85</td>
<td></td>
</tr>
<tr>
<td>This represents Line D4Z capacity. There is no capacity to export to Ontario through Line H4Z.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bryson-Paugan (Qc)/Ottawa (Ont.)</td>
<td>410</td>
<td>410</td>
<td></td>
</tr>
<tr>
<td>Limitations on the Québec system under peak load conditions restrict deliveries as follows P33C - 345 MW and X2Y – 65 MW. There is no capacity to export to Ontario through Line Q4C.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Outaouais (Qc)/Hawthorne (Ont.)</td>
<td>1,250</td>
<td>1,230</td>
<td></td>
</tr>
<tr>
<td>HVDC back-to-back facility at Outaouais. Normally Ontario will schedule up to 1,230 MW allowing for a TRM of 20 MW.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,955</td>
<td>2,935</td>
<td></td>
</tr>
</tbody>
</table>

Note: These capabilities may not correspond to exact ATC values posted in Hydro-Québec’s OASIS system since existing transmission services commitments are not considered. For real-time ATC values, please visit [http://www.oatioasis.com/hqt/index.html](http://www.oatioasis.com/hqt/index.html).
<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MISO (Michigan) / ONT</strong></td>
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<td></td>
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<tr>
<td>Lines L4D, L51D, J5D, B3N</td>
<td>1,750</td>
<td>1,550</td>
<td>The TRM is 200 MW</td>
</tr>
<tr>
<td>Total</td>
<td>1,750</td>
<td>1,550</td>
<td></td>
</tr>
<tr>
<td><strong>MISO (Manitoba-Minnesota) / ONT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NW / MAN Lines K21W, K22W</td>
<td>368</td>
<td>343</td>
<td>Flows into Ontario include flows on circuit SK1 of 68 MW. The TRM on the K21W, K22W interface is 25 MW.</td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>100</td>
<td>80</td>
<td>The TRM is 20 MW.</td>
</tr>
<tr>
<td>Total</td>
<td>468</td>
<td>423</td>
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<tr>
<td><strong>PJM / New York</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>PJM AC Ties</td>
<td>2,450</td>
<td>2,150</td>
<td>The TRM is 300 MW</td>
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<tr>
<td>PJM/NYC Linden VFT</td>
<td>315</td>
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<td></td>
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<td>PJM/Long Island Neptune Cable</td>
<td>660</td>
<td>660</td>
<td></td>
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<td>PJM/NYC HTP DC/DC Tie</td>
<td>660</td>
<td>660</td>
<td></td>
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<tr>
<td>Total</td>
<td>4,085</td>
<td>3,785</td>
<td></td>
</tr>
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</table>
Appendix IV – Demand Forecast Methodology

Reliability Coordinator area Methodologies

Maritimes
The Maritimes Area demand is the mathematical sum of the forecasted weekly peak demands of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes Area demand included a coincidence factor, the forecast demand would be approximately 1 to 3 percent lower.

For New Brunswick, the demand forecast is based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the load forecast is based on a 10-year weather average measured at the major load center, 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.

For Prince Edward Island, the demand forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6 percent based upon the four year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 5.0 and 9.0 percent (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models. Nova Scotia uses 5 percent as the Extreme Load Forecast Margin while the rest of the Maritimes uses 9 percent after similar analysis on their part.

New England
ISO New England’s energy model is an annual model of the total energy of the ISO-NE area, using real income, the real price of electricity, economics, and weather variables as drivers. Income is a proxy for all economic activity.
The peak-load model is a monthly model of the typical daily peak for each month, producing forecasts of weekly, monthly, and seasonal peak loads over a 10-year period. Daily peak loads are modeled as a function of energy, weather, and a time trend on weather for the summer months to capture the increasing sensitivity of peak load to weather due to the increasing cooling load.

The reference (normal) demand forecast, which has a 50 percent chance of being exceeded, is based on weekly weather distributions and the monthly model of typical daily peak. The weekly weather distributions are built using 20 years of temperature data at the time of daily electrical peaks (for nonholiday weekdays). A reasonable approximation for “normal weather” associated with the winter peak is 7.0°F and with the summer peak is 90.2°F. The extreme demand forecast, which has a 10 percent chance of being exceeded, is associated with a winter peak of 1.6°F and a summer peak of 94.2°F.10

New England has deployed the Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability on a zonal level by taking into account conflicting weather patterns, for example, when the Boston zone is forecasted to be 5°F while the Hartford area is forecast to be 30°F. This zonal forecast ensures an accurate reliability commitment on a regional level. The loads for the eight zones are then summed to estimate a total New England load, adding an additional New England load forecast to its Advanced Neural Network (ANN) models and Similar-Day (SimDay) analyses).

New York

The NYISO conducts load forecasting for the New York Control Area (“NYCA”) and for localities within the NYCA. The NYISO employs a two-stage process in developing load forecasts for each of the eleven zones within the NYCA. In the first stage, zonal load forecasts are based upon econometric projections. These forecasts assume a conventional portfolio of appliances and electrical technologies. The forecasts also assume that future improvements in energy efficiency measures will be similar to those of the recent past and that spending levels on energy efficiency programs will be similar to recent history. In the second stage the NYISO adjusts the econometric forecasts to explicitly reflect a projection of the energy savings resulting from statewide energy efficiency programs, impacts of new building codes and appliance efficiency standards and a projection of energy usage due to electric vehicles. In addition to the baseline forecast the NYISO also produces high and low forecasts for each zone that represent extreme weather conditions. The forecast is developed by the NYISO using a

Temperature-Humidity Index (THI) which is representative of normal weather during peak demand conditions.

The weather assumptions for most regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

Individual utilities include the peak demand impact of demand side management programs in their forecasts. Each investor owned utility, the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (NYPA), and the Long Island Power Authority (LIPA), maintain a database of installed measures from which estimates of impacts can be determined. The impact evaluation methodologies and measurement and verification standards are specified by the state's evaluation advisory committee known as "E2", in which the NYISO participates, and that provides input to the New York Department of Public Service staff reporting to the New York Public Service Commission.

There are two higher-than-expected scenarios forecast for the NYCA. One is a forecast without the impacts of energy efficiency programs or behind-the-meter solar photovoltaic generation. The second is a forecast based on extreme weather conditions, set to the 90th percentile of typical peak-producing weather conditions.

**Ontario**

The Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by non-registered generation. The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic data, conservation, embedded generation and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy, minimum and peak demand, including zone and system wide projections. IESO produces a forecast of hourly demand by zone. From this forecast the following information is available:

- hourly peak demand
- hourly minimum demand
- hourly coincident and non-coincident peak demand by zone
• energy demand by zone

These forecasts are generated based on a set of weather and economic assumptions. IESO uses a number of different weather scenarios to forecast demand. The appropriate weather scenarios are determined by the purpose and underlying assumptions of the analysis. The base case demand forecast uses a median economic forecast and monthly normalized weather. Multiple economic scenarios are only used in longer term assessments. A quantity of price-responsive demand is also forecast based on market participant information and actual market experience.

A consensus of four major, publicly available provincial forecasts is used to generate the economic drivers used in the model. In addition, forecast data from a service provider is purchased to enable further analysis and insight. Population projections, labour market drivers and industrial indicators are utilized to generate the forecast of demand. The impact of conservation measures are decremented from the demand forecast, which includes demand reductions due to energy efficiency, fuel switching and conservation behaviour (including the impact smart meters).

In Ontario, demand management programs include Demand Response programs and the dispatchable loads program. Historical data is used to determine the quantity of reliably available capacity, which is treated as a resource to be dispatched. Embedded generation leads to a reduction in “on-grid” demand on the grid, which is decremented from the demand forecast.

Ontario uses 31 years of history to calculate a weather factor to represent the MW impact on demand if the weather conditions (temperature, wind speed, cloud cover and humidity) are observed in the forecast horizon. Weather is sorted on a monthly basis, and for the extreme weather scenario, Ontario uses the maximum value from the sorted history.

For determining wind derating factors, Ontario uses seasonal contribution factors based on median historical hourly production values from September 2006 to the present. The wind contribution factors are updated annually.

Québec

Hydro-Québec’s demand and energy-sales forecasting is Hydro-Québec Distribution’s responsibility. First, the energy-sales forecast is built upon the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.
The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use/sector peak demands is the total monthly peak demand.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 43-year temperature database (1972–2014), adjusted by 0.30°C (0.54°F) per decade starting in 1972 to account for climate change. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 301 different demand scenarios. Weather uncertainty is calculated from these 301 demand scenarios (energy and peak). Load uncertainty is due to the uncertainty in economic and demographic variables affecting demand forecast and to residual errors from the models.

Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty. This Overall Uncertainty is lower during the summer than during the winter. For example, at the summer peak, weather conditions uncertainty is about 450 MW, equivalent to one standard deviation. During winter, this uncertainty is about 1,450 MW.

TransÉnergie – the Québec system operator – then determines the Québec Balancing Authority Area forecasts using Hydro-Québec Distribution’s forecasts (HQ internal demand) and accounting for agreements with different private systems within the Balancing Authority Area. The forecasts are updated on an hourly basis, within a 12-day horizon according to information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area. Forecasts on a minute basis are also produced within a two day horizon. TransÉnergie has a team of meteorologists who feed the demand forecasting model with accurate climatic observations and precise weather forecasts. Short term changes in industrial loads and agreements with different private systems within the Balancing Authority Area are also taken into account on a short term basis.
Appendix V - NPCC Operational Criteria and Procedures

NPCC Directories Pertinent to Operations

NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System

- Description: This directory provides a “design-based approach” to ensure the bulk power system is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies. Includes Appendices F and G “Procedure for Operational Planning Coordination” and “Procedure for Inter Reliability Coordinator area Voltage Control”, respectively.

NPCC Regional Reliability Reference Directory #2 - Emergency Operations

- Description: Objectives, principles and requirements are presented to assist the NPCC Reliability Coordinator areas in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency.

NPCC Regional Reliability Reference Directory #5 – Reserve

- Description: This directory provides objectives, principles and requirements to enable each NPCC Reliability Coordinator Area to provide reserve and simultaneous activation of reserve.

NPCC Regional Reliability Reference Directory #6 – “Reserve Sharing Groups”

- Description: This directory provides the framework for Regional Reserve Sharing Groups within NPCC. It establishes the requirements for any Reserve Sharing Groups involving NPCC Balancing Authorities.

NPCC Regional Reliability Reference Directory #8 - System Restoration

- Description: This directory provides objectives, principles and requirements to enable each NPCC Reliability Coordinator Area to perform power system restoration following a major event or total blackout.

Note - Directory #8 is presently being revised by the NPCC Task Forces on Coordination of Operation and Coordination of Planning.

NPCC Regional Reliability Reference Directory # 9- Verification of Generator Gross and Net Real Power Capability

- Description: This document establishes the minimum criteria to verify the Gross Real Power Capability and Net Real Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system.
Note-Directory #9 is presently being revised by the NPCC Task Forces on Coordination of Operation and Coordination of Planning.

NPCC Regional Reliability Reference Directory # 10- Verification of Generator Gross and Net Reactive Power Capability

- Description: This document establishes the minimum criteria to verify the Gross Reactive Power Capability and Net Reactive Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in NERC Standard MOD-025-1, “Verification of Generator Gross and Net Reactive Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

Note-Directory #10 is presently being revised by the NPCC Task Forces on Coordination of Operation and Coordination of Planning.

NPCC Regional Reliability Reference Directory # 12-Underfrequency Load Shedding Requirements

- Description: This document presents the basic criteria for the design and implementation of under frequency load shedding programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

A-10 Classification of Bulk Power System Elements

- Description: This Classification of Bulk Power System Elements (Document A-10) provides the methodology for the identification of those elements of the interconnected NPCC Region to which NPCC bulk power system criteria are applicable. Each Reliability Coordinator area has an existing list of bulk power system elements. The methodology in this document is used to classify elements of the bulk power system and has been applied in classifying elements in each Reliability Coordinator area as bulk power system or non-bulk power system.

NPCC Procedures Pertinent to Operations

C-01 NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures

- Description: The NPCC Emergency Preparedness Conference Call establishes communications among the Operations Managers of the Reliability Coordinator
(RC) Areas in NPCC to discuss issues related to the adequacy and security of the interconnected bulk power supply system of the Northeast Power Coordinating Council.

**C-15  Procedures for Solar Magnetic Disturbances on Electrical Power Systems**
- **Description:** This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

**C-35  NPCC Inter-Area Power System Restoration Reference Document**
- **Description:** This procedure provides guidance and training material to the system operator to manage system restoration events that affect the NPCC Reliability Coordinator areas and adjoining Reliability Coordinator areas.

**C-36  Procedures for Communications during Emergencies**
- **Description:** This procedure establishes the types of communications that should take place between Reliability Coordinator area system operators and with external agencies during an emergency. It also indicates the data that should be collected during and after a major system event.

*Note: Procedure Document C-36 is merging with Procedure Document C-01.*

**C-43  NPCC Operational Review for the Integration of New Facilities**
- **Description:** The document provides the procedure to be followed in conducting operations reviews of new facilities being added to the power system. This procedure is intended to apply to new facilities that, if removed from service, may have a significant, direct or indirect impact on another Reliability Coordinator area’s inter-Area or intra-Area transfer capabilities. The cause of such impact might include stability, voltage, and/or thermal considerations.
Appendix VI - Web Sites

Independent Electricity System Operator
  http://www.ieso.ca/

ISO- New England
  http://www.iso-ne.com

Maritimes
  Maritimes Electric Company Ltd.
  http://www.maritimeelectric.com
  New Brunswick Power Corporation
  http://www.nbpower.com
  New Brunswick Transmission and System Operator
  http://tso.nbpower.com/public
  Nova Scotia Power Inc.
  http://www.nspower.ca/
  Northern Maine Independent System Administrator
  http://www.nmisa.com

Midwest Reliability Organization
  http://www.midwestreliability.org

New York ISO
  http://www.nyiso.com/

Northeast Power Coordinating Council, Inc.
  http://www.npcc.org/

North American Electric Reliability Corporation
  http://www.nerc.com

ReliabilityFirst Corporation
  http://www.rfirst.org

TransEnergie
  http://www.hydroquebec.com/
Appendix VII - References

CP-8 2015-16 Winter Multi-Area Probabilistic Reliability Assessment

NPCC Reliability Assessment for Winter 2015-16
Northeast Power Coordinating Council, Inc.
Multi-Area Probabilistic Reliability Assessment
For
Winter 2015/16

RCC Approved

September 10, 2015

Conducted by the
NPCC CP-8 Working Group
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Appendix VIII - CP-8 2015/16 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

**CP-8 WORKING GROUP**

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The CP-8 Working Group acknowledges the efforts of Messrs. Mark Walling and Chris Cox, GE Energy Consulting, and Patricio Rocha-Garrido, the PJM Interconnection, and thanks them for their assistance in this analysis.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>TABLE OF CONTENTS</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXECUTIVE SUMMARY</td>
<td>4</td>
</tr>
<tr>
<td>Introduction</td>
<td>4</td>
</tr>
<tr>
<td>Results</td>
<td>4</td>
</tr>
<tr>
<td>Conclusions</td>
<td>6</td>
</tr>
<tr>
<td>INTRODUCTION</td>
<td>7</td>
</tr>
<tr>
<td>MODEL ASSUMPTIONS</td>
<td>8</td>
</tr>
<tr>
<td>Load Representation</td>
<td>8</td>
</tr>
<tr>
<td>Load Shape</td>
<td>8</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>9</td>
</tr>
<tr>
<td>Generation</td>
<td>10</td>
</tr>
<tr>
<td>Wind Resource Modeling</td>
<td>11</td>
</tr>
<tr>
<td>Unit Availability</td>
<td>12</td>
</tr>
<tr>
<td>Transfer Limits</td>
<td>13</td>
</tr>
<tr>
<td>Operating Procedures to Mitigate Resource Shortages</td>
<td>14</td>
</tr>
<tr>
<td>Assistance Priority</td>
<td>15</td>
</tr>
<tr>
<td>Modeling of Neighboring Regions</td>
<td>16</td>
</tr>
<tr>
<td>WINTER 2014/15 SUMMARY</td>
<td>19</td>
</tr>
<tr>
<td>ANALYSIS</td>
<td>27</td>
</tr>
<tr>
<td>Winter 2015/16 Results</td>
<td>27</td>
</tr>
<tr>
<td>Base Case Scenario</td>
<td>27</td>
</tr>
<tr>
<td>Base Case Assumptions</td>
<td>28</td>
</tr>
<tr>
<td>Severe Case Scenario</td>
<td>33</td>
</tr>
<tr>
<td>Severe Case Assumptions</td>
<td>34</td>
</tr>
<tr>
<td>Conclusions</td>
<td>35</td>
</tr>
</tbody>
</table>
APPENDICES

<table>
<thead>
<tr>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>A) OBJECTIVE AND SCOPE OF WORK</td>
</tr>
<tr>
<td>B) EXPECTED NEED FOR OPERATING PROCEDURES</td>
</tr>
<tr>
<td>Table 7 - Base Case Assumptions (2003/04 Load Shape)</td>
</tr>
<tr>
<td>Table 8 - Severe Case Scenario (2003/04 Load Shape)</td>
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<td>C) MULTI-AREA RELIABILITY SIMULATION PROGRAM DESCRIPTION</td>
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EXECUTIVE SUMMARY

Introduction
This study estimated the use of NPCC Area Operating Procedures designed to mitigate resource shortages for the winter of 2015/16 (November 2015 through March 2016). The CP-8 Working Group’s effort is consistent with the CO-12 Working Group’s study, "NPCC Reliability Assessment for Winter 2015-16", December 2015. 1

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by NPCC to conduct the simulations.

Results
For the November 2015 - March 2016 period, Figure EX-1a shows the estimated use of the indicated operating procedures under the Base Case assumptions for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated).

For the November 2015 - March 2016 period, Figure EX-1b shows the estimated use of the indicated operating procedures under the Base Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).

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1 See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx
For the November 2015 - March 2016 period, Figure EX-2a shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the expected load level. The expected load level results were based on the probability-weighted average of the seven load levels simulated.
For the November 2015 - March 2016 period, Figure EX-2b shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level, representing the second to highest load level, having approximately a 6% chance of being exceeded.

**Conclusions**

As shown in Figure EX-1a, the use of operating procedures designed to mitigate resource shortages is not expected for Québec, the Maritimes, Ontario, New York, and New England under the assumed Base Case conditions for the expected load level. As shown in Figure EX-1b, only the Maritimes Areas show a minimal need for use of operating procedures in response to a capacity deficiency this winter under the Base Case, extreme load conditions.

The expected load level results were based on the probability-weighted average of the seven load levels simulated. The extreme load level represents the second to highest load level, having approximately a 6% chance of being exceeded.

As shown in Figures EX-2a and 2b, the Maritimes Area, and to a lesser extent, New England show a need for use of operating procedures in response to a capacity deficiency this winter under the Severe Case conditions.
INTRODUCTION

This study estimated the use of NPCC Area operating procedures to mitigate resource shortages for November 2015 through March 2016. The Working Group’s efforts are consistent with the NPCC CO-12 Working Group’s study, "NPCC Reliability Assessment for Winter 2015-16", December 2015. ¹

The development of this Working Group’s assessment was in response to the following recommendation from the "NPCC Reliability Assessment for Winter 2004/05". ¹

“The CO-12 assessment of the Summer Operating Period is accompanied by a corresponding multi area probabilistic assessment of Loss of Load Expectations and of the projected use of Operating Procedures designed to mitigate resource shortages. This assessment was not performed for this Winter Operating Period. For completeness in the assessment of the Winter Operating Period, the CO-12 Working Group recommends that TFCO and TFCP review the merits of having this assessment performed for future Winter Operating Periods.”

The database developed by the CP-8 Working Group for the "NPCC Reliability Assessment for Summer 2015", April 30, 2015, ² was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the winter 2015/16 assessment period.

This report is organized in the following manner: after a brief introduction, specific model assumptions are presented followed by an analysis of the results based on the scenarios simulated. The Working Group's Objective and Scope of Work is shown in Appendix A. Tables presenting the corresponding results for the Base Case and Severe Case simulations are listed in Appendix B. Appendix C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 3.18 was used for this assessment.

---

¹ See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

² See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx
MODEL ASSUMPTIONS

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. Table 1 summarizes each NPCC Area's winter peak load assumptions for the winter 2015/16.

Table 1
Assumed NPCC 2015/16 Peak Loads – MW
(2003/04 Load Shapes)

<table>
<thead>
<tr>
<th>Area</th>
<th>Expected Peak</th>
<th>Extreme Peak *</th>
<th>Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec* (Q)</td>
<td>38,280</td>
<td>41,710</td>
<td>January</td>
</tr>
<tr>
<td>Maritimes Area** (MT)</td>
<td>5,202</td>
<td>5,681</td>
<td>January</td>
</tr>
<tr>
<td>New England (NE)</td>
<td>22,740</td>
<td>23,611</td>
<td>January</td>
</tr>
<tr>
<td>New York (NY)</td>
<td>27,410</td>
<td>28,260</td>
<td>January</td>
</tr>
<tr>
<td>Ontario (ON)</td>
<td>22,380</td>
<td>23,541</td>
<td>January</td>
</tr>
</tbody>
</table>

* Extreme Peak based on load forecast uncertainty for peak month.
** Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the system administered by the Northern Maine Independent System Administrator (NMISA).

Load Shape
In 2006, the Working Group considered two load shape assumptions for the winter multi-area assessment:
- a 2002/03 load shape representative of a winter weather pattern with a typical expectation of cold days; and,
- a 2003/04 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

Review of the results for both load shape assumptions indicated only slight differences in the results. The Working Group agreed that the weather patterns associated with the 2003/04 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments. Upon review of subsequent winter weather experience, the Working Group agreed that the 2003/04 load shape assumption be again used for this analysis.

The growth rate in each month’s peak was used to escalate Area loads to match the Area’s winter demand and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.
Figure 1 shows the diversity in the NPCC area load shapes used in this analysis for the 2003/04 load shape assumptions.

![2015/2016 Projected Coincident Expected Monthly Peak Loads - MW Composite Load Shape](image)

**Figure 1 – 2015/16 Projected Monthly Peak Loads for NPCC Areas**

*(2003/04 Load Shape)*

**Load Forecast Uncertainty**

Peak load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the peak load forecast, due to weather and/or 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 the load can vary on a monthly basis, Table 2 shows the values assumed for January 2016. Table 2 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 highlighted in Table 2.

### Table 2
Per Unit Variation in Load Assumed for the Month of January 2016

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>1.0896 1.0896 1.0415 0.9991 0.9601 0.9207 0.9104</td>
</tr>
<tr>
<td>MT</td>
<td>1.1380 1.0920 1.0460 1.0000 0.9540 0.9080 0.8620</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>1.0779 1.0519 1.0260 1.0000 0.9740 0.9481 0.9221</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

Tables 3(a) and 3(b) summarize the winter 2015/16 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Base Case conditions are consistent with the assumptions used in the NPCC CO-12 Working Group, "NPCC Reliability Assessment for Winter 2015-16", December 2015.

### Table 3(a)
NPCC Capacity and Load Assumptions for January 2016 - MW
Base Case - Expected Load

<table>
<thead>
<tr>
<th>Assumed Capacity</th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchase/Sale</td>
<td>808</td>
<td>-200</td>
<td>1,226</td>
<td>-188</td>
<td>-500</td>
</tr>
<tr>
<td>Peak Load</td>
<td>38,280</td>
<td>5,202</td>
<td>22,740</td>
<td>27,410</td>
<td>22,380</td>
</tr>
<tr>
<td>Demand Response</td>
<td>1,366</td>
<td>251</td>
<td>2,285</td>
<td>1,132</td>
<td>909</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>11.8</td>
<td>47.3</td>
<td>60.4</td>
<td>50.2</td>
<td>34.2</td>
</tr>
<tr>
<td>Annual Weighted</td>
<td>98.6</td>
<td>91.7</td>
<td>90.2</td>
<td>84.2</td>
<td>88.6</td>
</tr>
<tr>
<td>Average Unit</td>
<td>0</td>
<td>0</td>
<td>2,537</td>
<td>1,216</td>
<td></td>
</tr>
<tr>
<td>Availability (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scheduled</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3 New England Assumed Capacity reflects the modeling of wind at 15% of nameplate value
4 Based on the 2003/04 Load Shape assumption; internal Québec load shown.
Table 3 (b)
NPCC Capacity and Load Assumptions for January 2016 - MW
Severe Assumptions Scenario - Extreme Load

<table>
<thead>
<tr>
<th></th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>39,640</td>
<td>6,785</td>
<td>27,965</td>
<td>36,220</td>
<td>28,980</td>
</tr>
<tr>
<td>Purchase/Sale</td>
<td>808</td>
<td>-200</td>
<td>1,226</td>
<td>-188</td>
<td>-500</td>
</tr>
<tr>
<td>Peak Load 1</td>
<td>41,710</td>
<td>5,681</td>
<td>23,611</td>
<td>28,260</td>
<td>23,541</td>
</tr>
<tr>
<td>Demand Response (MW)</td>
<td>1,366</td>
<td>251</td>
<td>2,285</td>
<td>1,132</td>
<td>909</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>0.3</td>
<td>20.3</td>
<td>33.3</td>
<td>31.5</td>
<td>24.8</td>
</tr>
<tr>
<td>Scheduled Maintenance</td>
<td>-</td>
<td>0</td>
<td>0</td>
<td>1,429</td>
<td>2,735</td>
</tr>
</tbody>
</table>

Wind Resource Modeling

Maritimes
The Maritimes provides an hourly historical wind output for each sub-area. This profile is then scaled according to the wind online at the time of the regional peak.

New England
New England utilizes units of a fixed capacity (that varies seasonally) representing the Seasonal Claimed Capability to represent their wind resources.

New York
New York provides an hourly historical wind profile for each wind plant, based on the 2013 wind production data.

Ontario
Capacity limitations due to variability of wind generators are captured by providing probability density functions from which stochastic selections are made by the MARS software. Wind generation is aggregated on a zonal basis and modelled as an energy-limited resource with a cumulative probability density function (CPDF) which represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs vary by month and season.

Quebec
Quebec utilizes units of a fixed capacity (that varies seasonally) to represent the expected capacity. The expected capacity at peak is 30% of the Installed (Nameplate) capacity, with the exception of a small amount (roughly 3%) which is derated for all years of the study.

5 Maintenance shown is for the week of the monthly peak load. Capacity shown for Québec adjusted for scheduled maintenance and other restrictions.
Unit Availability
Details regarding the NPCC Area’s assumptions for generator unit availability are described in the respective Area’s most recent "NPCC Comprehensive Review of Resource Adequacy". In addition, the following Areas provided the following:

Quebec
The planned outages for the winter period are reflected in this assessment. The amount of planned outages is consistent with historical values.

Ontario
Ontario’s generating unit availability was based on IESO “18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from July 2015 – December 2016” (released June 22, 2015).

The capacity values and planned outage schedules for thermal units are based on monthly maximum continuous ratings and planned outage information contained in market participant submissions. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied. Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources.

New England
This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon the approved maintenance schedules. Individual generating unit forced outage assumptions were based on the unit’s historical data and North American Reliability Council (NERC) average data for the same class of unit. A more detailed description of the modeling assumptions can be found by referring to the corresponding FERC filings concerning the ISO-New England Installed Capacity Requirement and related values for the 3rd Reconfiguration Auction for the 2015/2016 Capability Year.

New York

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

Figure 2 depicts the system that was represented in this Assessment, showing Area and assumed Base Case transfer limits for the winter 2015/16 period. New York Area internal transmission representation was consistent with the assumptions used in the New York ISO report 9 - "Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2015 – 2016 Capability Year" New York ISO, January 14, 2015 and the “New York Control Area Installed Capacity Requirements for the Period May 2015 – April 2016” New York State Reliability Council, December 5, 2014 report. 10

The New England internal transmission representation is consistent with assumptions currently being developed for the 2015 New England Regional System Plan. 11

Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York. 12

Figure 2 - Assumed Transfer Limits Between Areas

Appendix VIII - CP-8 2015/16 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

Tie transfer limits between Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Figure 2 acronyms and notes are as follows:

Chur. - Churchill Falls NOR - Norwalk – Stamford RF - ReliabilityFirst
MANIT - Manitoba BHE - Bangor Hydro Electric NB - New Brunswick
ND - Nicolet-Des Cantons Mtl - Montréal PEI - Prince Edward Island
JB - James Bay C MA - Central MA CT - Connecticut
MAN - Manicouagan W MA - Western MA NS - Nova Scotia
NE - Northeast (Ontario) NBM - Millbank NW - Northwest (Ontario)
MRO - Midwest Reliability Organization Que - Québec Centre Cdrs - Cedars
NM - Northern Maine Centre

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 actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reduced operating reserves. Table 4 summarizes the load relief assumptions modeled for each NPCC Area.

Table 4 - NPCC Operating Procedures to Mitigate Resource Shortages
2015/16 Winter Load Relief Assumptions - MW

<table>
<thead>
<tr>
<th>Actions</th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus Appeals</td>
<td>1,366</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>148</td>
</tr>
<tr>
<td>RT-DR * / SCR / EDRP</td>
<td>0</td>
<td>0</td>
<td>379</td>
<td>756</td>
<td>1.00%</td>
</tr>
<tr>
<td>SCR Load / Man. Volt. Red.</td>
<td>0</td>
<td>0</td>
<td>0.20%</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>500</td>
<td>233</td>
<td>625</td>
<td>655</td>
<td>473</td>
</tr>
<tr>
<td>3. Voltage Reduction</td>
<td>250</td>
<td>0</td>
<td>152</td>
<td>1.02%</td>
<td>0.01%</td>
</tr>
<tr>
<td>Interruptible Load 15</td>
<td>0</td>
<td>251</td>
<td>0</td>
<td>0</td>
<td>581</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>750</td>
<td>505</td>
<td>0</td>
<td>0</td>
<td>945</td>
</tr>
<tr>
<td>RT-EG 16</td>
<td>0</td>
<td>0</td>
<td>168</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Appeals / Curtailments</td>
<td>0</td>
<td>0</td>
<td>204</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5. 5% Voltage Reduction</td>
<td>0</td>
<td>0</td>
<td>1,550</td>
<td>1,310</td>
<td>0.69%</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>328</td>
</tr>
<tr>
<td>Appeals / Curtailments</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

* Real-Time Demand Response

**Notes:**

13 Values for New England’s Real-Time Demand Resources and Real-Time Emergency Generation have been derated to account for historical availability performance.
14 Values for New York’s SCR and EDRP Programs have been derated to account for historical availability.
15 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.
16 Real Time Emergency Generation.

NPCC CP-8 Working Group 14 RCC approved – September 10, 2015
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 4 was a reasonable approximation for this analysis.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) 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.

**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.
Modeling of Neighboring Regions
For the scenarios studied, a detailed representation of RF (ReliabilityFirst) and the MRO-US (Midwest Reliability Organization – US portion) was modeled. The assumptions are summarized in Table 5.

Table 5
PJM, RF-OTH, and MRO 2015/16 Base Case Assumptions

<table>
<thead>
<tr>
<th></th>
<th>PJM</th>
<th>RF-OTH</th>
<th>MRO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>129203</td>
<td>35556</td>
<td>25914</td>
</tr>
<tr>
<td>Peak Month</td>
<td>January</td>
<td>January</td>
<td>January</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>179287</td>
<td>49308</td>
<td>36340</td>
</tr>
<tr>
<td>Purchase/Sale (MW)</td>
<td>3201</td>
<td>2067</td>
<td>1589</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>41.8</td>
<td>43.3</td>
<td>44.5</td>
</tr>
<tr>
<td>Weighted Unit Availability (%)</td>
<td>85.7</td>
<td>85.2</td>
<td>85.1</td>
</tr>
<tr>
<td>Operating Reserves (MW)</td>
<td>3,400</td>
<td>2,206</td>
<td>1,700</td>
</tr>
<tr>
<td>Curtailable Load (MW)</td>
<td>786</td>
<td>3694</td>
<td>2692</td>
</tr>
<tr>
<td>No 30-min Reserves (MW)</td>
<td>2,765</td>
<td>1,470</td>
<td>1,200</td>
</tr>
<tr>
<td>Voltage Reduction (MW)</td>
<td>2,201</td>
<td>1,100</td>
<td>1,100</td>
</tr>
<tr>
<td>No 10-min Reserves (MW)</td>
<td>635</td>
<td>736</td>
<td>500</td>
</tr>
<tr>
<td>Appeals (MW)</td>
<td>400</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (%)</td>
<td>100.0 +/- 3.35, 6.69, 10.04</td>
<td>100.0 +/- 2.79, 5.58, 8.37</td>
<td>100.0 +/- 2.79, 5.58, 8.37</td>
</tr>
</tbody>
</table>

Figure 3 shows the 2015/16 Projected Monthly Expected Peak Loads for NPCC, PJM, RF-OTH (Other) and the MRO for the 2003/04 Load Shape assumption.

ReliabilityFirst is the successor organization to the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations.

The RFC-OTH (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 NERC Electricity Supply & Demand (ES&D), provided by PJM. The modeling of RFC-OTH is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-OTH area is the non-PJM RTO region that was formerly in either MAIN or ECAR. The MAIN and ECAR boundaries do not correctly define the new RFC boundaries, but this definition insures consistency within the use of the NERC ES&D data.

**PJM-RTO Load Model**

The load model used for the PJM-RTO in this study is consistent with the PJM Planning division's technical methods. 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

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18 Please refer to PJM Manuals 19 and 20 at [http://www.pjm.com/~media/documents/manuals/m19-redline.ashx](http://www.pjm.com/~media/documents/manuals/m19-redline.ashx) and, [http://www.pjm.com/~media/documents/manuals/m20-redline.ashx](http://www.pjm.com/~media/documents/manuals/m20-redline.ashx) for technical specifics.
Load forecast uncertainty was modeled consistent with recent planning PJM models considering seven load levels, each with an associated probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years the model is based on, sampling size, and how many years ahead in the future the load forecast is being derived for.

**Expected Resources**
All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Load Management (LM) is modeled as an Emergency Operating Procedure. The total available MW as LM is as per results from the PJM’s capacity market.

**Expected Transmission Projects**
The transfer values shown in the study are reflective of peak emergency 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.

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19 See: http://www.pjm.com/~/media/documents/reports/2015-load-forecast-report.ashx
21 See: http://www.pjm.com/planning.aspx
WINTER 2014/15 SUMMARY

Highlights - (January 2015 – March 2015 cold season)

The cold season average temperature for the contiguous U.S. was 40.7°F, 1.7°F above the 20th century average and the 15th warmest on record.

Locations from the Rockies to the West Coast were much warmer than average. Arizona, California, Nevada, Oregon, and Washington each had their warmest cold season on record. Six additional states had one of their 10 warmest cold seasons.

Alaska had its third warmest cold season on record with a temperature of 15.7°F, 5.9°F above average. Only the cold seasons of 2002/03 and 2000/01 were warmer.

Below-average temperatures stretched from the Mississippi River Valley to the East Coast. While no state was top 10 cold, Ohio had its 12th coldest cold season on record. Across the East, a warm start to the cold season nearly balanced record and near-record cold temperatures at the end of the six-month period.

Northeast Region

January

2015 got off to a cold start in the Northeast. January's average temperature of 20.0 degrees F (-6.7 degrees C) was 3.2 degrees F (1.8 degrees C) colder than normal. All twelve states experienced colder-than-normal temperatures, with departures ranging from 1.5 degrees F (0.8 degrees C) below normal in Delaware to 4.5 degrees F (2.5 degrees C) below normal in New York.

A Nor'easter struck the region from January 26-28. Some of the largest snow totals were: 36.0 inches (91.4 cm) in Hudson, Massachusetts; 33.5 inches (85.1 cm) in Thompson, Connecticut; 33.2 inches (84.3 cm) in Nashua, New Hampshire; 31.5 inches (80.0 cm) in Sanford, Maine; 30.0 inches (76.2 cm) in Orient, New York; and 28.5 inches (72.4 cm) in Burrillville, Rhode Island. The storm packed hurricane-force winds, with peak sustained winds of 59 mph (26 m/s) and a peak gust of 78 mph (35 m/s) in Nantucket, Massachusetts. The winds caused significant coastal flooding in parts of Massachusetts, and blizzard conditions in coastal areas of Maine and New Hampshire.

February

February was an extraordinarily cold month in the Northeast. The region's average temperature of 13.5 degrees F (-10.3 degrees C) was 12.7 degrees F (7.1 degrees C) below normal. This made it the 2nd coldest February on record behind 1934, which had an average temperature of 12.0 degrees F (-11.1 degrees C). Departures for the states ranged from 14.1 degrees F (7.8 degrees C) below normal in New York and Vermont to 10.1 degrees F (5.6 degrees C) below normal in Delaware. Eight states had their 2nd coldest February on record: Connecticut, Maine, Massachusetts, New Hampshire, New

22 See: http://www.ncdc.noaa.gov/sotc/national/201503
York, Pennsylvania, Rhode Island, and Vermont. West Virginia had its 4th coldest February on record, while Maryland and New Jersey had their 6th coldest February and Delaware had its 7th coldest February. Winter was also colder than normal. The region's average temperature of 21.9 degrees F (-5.6 degrees C) was 4.0 degrees F (2.2 degrees C) below normal. Departures for the states ranged from 4.9 degrees F (2.7 degrees C) below normal in New York, making it the state's 17th coldest winter on record, to 3.0 degrees F (1.7 degrees C) below normal in West Virginia.

All 35 Northeast airport climate sites ranked the month among their top 20 coldest Februaries, with 15 of those sites having their coldest February on record. February was the all-time coldest month on record at seven sites, with an additional 27 sites ranking this February among their top 20 all-time coldest months. Twenty-six sites ranked this winter among their top 20 coldest winters.

Throughout February, the Northeast was affected by numerous storms, several of which dropped more than a foot (30 cm) of snow. On the 15th, strong winds from a Nor'easter caused up to 9 hours of blizzard conditions in parts of New England. Across the region, the storms caused frequent school and business closures, thousands of flight delays and cancellations, and power outages. Of the region's 35 major airport climate sites, 23 sites ranked the month among their top 20 snowiest Februaries. Fourteen of those sites also ranked this February among their top 20 all-time snowiest months. Boston, MA, and Worcester, MA, set multiple records including: snowiest February, all-time snowiest month, and snowiest winter. Boston received 64.8 inches (164.6 cm) of snow during February, which is more than the city normally gets in an entire snow season. Fifteen sites ranked this winter among their top 20 snowiest winters.

March
March was another colder-than-normal month in the Northeast. The region's average temperature of 29.2 degrees F (-1.6 degrees C) was 5.2 degrees F (2.9 degrees C) below normal, making it the 17th coldest March since 1895. All twelve states were colder than normal, with nine ranking the month among their top 20 coldest Marches on record: Rhode Island, 8th coldest; Massachusetts, 11th coldest; New Hampshire and Maine, 12th coldest; Connecticut, 13th coldest; New York, 15th coldest; Vermont, 17th coldest; and Pennsylvania, 18th coldest; and New Jersey, 20th coldest. Departures for the states ranged from 6.3 degrees F (3.5 degrees C) below normal in New York to 1.9 degrees F (1.1 degrees C) below normal in West Virginia. Pittsburgh, Pennsylvania, had its lowest temperature ever recorded in March with a low of -5 degrees F (-21 degrees C) on the 6th. The following day, on the 7th, Harrisburg, Pennsylvania, had its coldest-ever March day with a low of -1 degree F (-18 degrees C).

The largest winter storm of the month moved through the region from March 4 to 5, dropping up to 13 inches (33 cm) of snow. From early to mid-March, parts of West Virginia and western Pennsylvania dealt with flooding, which caused numerous road closures and evacuations. Mudslides and river ice caused damage in West Virginia. On March 15, Boston, Massachusetts, reached 108.6 inches (275.8 cm) of snow for the season, surpassing its old record for snowiest season (1995-96) by 1 inch (2.5 cm). Islip,
New York, had its snowiest March on record with 19.7 inches (50.0 cm), beating the old record of 13.6 inches (34.5 cm) set in 2009. Syracuse had its greatest number of consecutive days with at least two feet (61 cm) of snow on the ground, with 19 days (from February 19 to March 9), while Binghamton had its longest stretch of at least one foot (30 cm) of snow on the ground, with 40 days (from February 2 to March 13).

Load Comparison
Table 6 compares NPCC Area’s actual 2014-15 winter peak demands against the forecast assumptions.

<table>
<thead>
<tr>
<th>Area</th>
<th>Date</th>
<th>Actual (MW)</th>
<th>Forecast (Based on 2003/04 Load Shape)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Expected Peak</td>
</tr>
<tr>
<td>Québec</td>
<td>January 8, 2015</td>
<td>38,743</td>
<td>37,268</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td>February 24, 2015</td>
<td>5,314</td>
<td>5,249</td>
</tr>
<tr>
<td>New England</td>
<td>January 8, 2015</td>
<td>20,556</td>
<td>22,575</td>
</tr>
<tr>
<td>New York</td>
<td>January 7, 2015</td>
<td>24,648</td>
<td>27,316</td>
</tr>
<tr>
<td>Ontario</td>
<td>January 7, 2015</td>
<td>21,814</td>
<td>22,272</td>
</tr>
</tbody>
</table>

Québec
Internal peak hourly demand for winter 2014-2015 was established to be 38,743 MW on Thursday, January 8, 2015 at hour ending 08h00 EST. This value includes 979 MW of interruptible demand that was used at peak time. Montréal temperature at peak time was -24 °C (-11.2 °F) and wind speed was 19 km/hour (12 mph).

Winter 2014-15 was colder than average. Mean temperatures were about 2 °C (3.6 °F) lower than normal temperatures during that period. February was exceptionally cold, setting a new historical low for average temperature during that month in Montreal, with mean temperatures about 7 °C (12.6 °F) lower than normal temperatures.

Maritimes
The Maritimes Area load is the mathematical sum of the forecasted or actual peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator).

The actual winter peak was 5,314 MW and occurred on February 24, 2015. The Maritime Provinces did not experience any unexpected extreme or adverse weather conditions and did not require use of its Demand Response measures.
New England

Weather is one of the biggest drivers of peak demand and overall power usage: milder temperatures translate into lower demand, and extreme temperatures push up demand. While the region experienced fairly moderate weather during December 2014, temperatures dropped in January and became downright arctic in February. With an average monthly temperature of 16.9° F in New England, February 2015 was the coldest month on record, based on ISO New England historical statistics, which date back to 1960.

February 2015 set another record as the cold temperatures pushed up total energy usage higher than any other February. Yet, when considering the weather and temperatures were mild in December and average for January, peak demand and total winter electricity consumption were both lower than in winter 2013/2014:

- Demand for power reached its highest level on January 8, 2015, at 20,556 MW; the previous winter’s peak occurred on December 17, 2013, at 21,453 MW.
- New Englanders consumed 33,654 gigawatt-hours (GWh) of electricity from December 2014 through February 2015, slightly less than the 33,991 GWh consumed during the same period of the previous winter.

Although February was the coldest month, demand for electricity peaked in January for this winter period. As temperatures plummeted in February, consumer demand was lower because the holiday season had largely passed, which reduced the amount of electricity needed for decorative lighting. And in general, as the days grow longer, heating, lighting, and cooking activities don’t fall into such a narrow time frame when people arrive home.

Other reasons for lower peak demand and consumption include the frequent snow storms that led to schools, businesses, and in some cases government offices closing, as well as the effects of increased energy-efficiency in New England. Compared to the previous winter, regional energy efficiency measures reduced peak demand by an additional 265 MW.

A confluence of regional and global factors, advance planning and preparations, and delayed cold weather during winter 2014/2015 helped alleviate the operational issues and record-high prices seen during the previous winter.

The primary factors that helped ensure power system reliability in New England and keep price volatility in check, include:

- The 2014/2015 Winter Reliability Program provided incentives to generators to have oil inventory stored on site, or to have a contract for LNG deliveries to supplement pipeline gas supplies before the start of winter.
- December was mild, and the coldest winter weather didn’t arrive until February, when days were longer and electricity consumption was lower.

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More liquefied natural gas (LNG) supplies were drawn to New England from world LNG markets, because of the region’s high natural gas prices during the previous winter and high forward prices for delivery during winter 2014/2015. Global oil prices dropped dramatically during 2014, making oil-fired generation often more economic to run than natural-gas-fired generation and dampening both gas and electricity price volatility. Energy-efficiency measures helped reduce total power consumption and peak demand. As a result, New England’s generating resources and high-voltage power grid performed well throughout December, January, and February. Nevertheless, natural gas pipeline constraints continue to affect grid operations, wholesale energy costs, and the resource mix used to meet demand during the winter months.

The New England Power Grid operated well throughout the winter, due to close coordination with generators and gas pipeline operators helped operate the grid reliably during really cold days. Increased LNG injections were very helpful in maintaining grid reliability.

The Winter Reliability Program, was instrumental in augmenting the fuel security of the region, primarily by boosting oil inventory in the region; cold weather in February depleted fuel supplies after mild December kept oil tanks fuller than last season. Some problems late in the season with fuel barges getting through the ice and weather to dock and unload cargoes

OP No. 4 Actions 24
On Thursday, December 4, 2014, ISO New England implemented Master/Local Control Center Procedure No. 2 (M/LCC 2), Abnormal Conditions Alert and Operating Procedure No. 4 (OP No. 4), Action During a Capacity Deficiency, to manage a deficiency in Operating Reserve. The Morning Report projected an operating reserve surplus of 201 MW, based on the forecast load of 18,200 MW. The expected net import delivery for the peak hour was 2,789 MW.

At approximately 15:50, Hydro-Quebec TransÉnergie (HQ) curtailed 2,005 MW into New England, which included imports from Phase 2, Highgate, and New Brunswick wheeled transactions, due to the loss of two major 735 kV transmission lines in Quebec. All available capacity resources that could start in less than 2 hours were ordered on-line. At 16:00, M/LCC 2 was declared due to a capacity deficiency for all of New England. At 16:15, OP No. 4 Action 1 was implemented to manage the deficiency in 30 minute operating reserve.

Due to real-time system conditions in HQ, New England provided up to 450 MW of emergency energy sales to HQ. In addition to the emergency energy provided to HQ from New England, HQ provided up to 500 MW of capacity backed emergency energy to New Brunswick, which was wheeled through New England and returned to HQ through Phase 2. Action 1 of OP No. 4 was cancelled at 20:45 and M/LCC 2 was cancelled at 18:00 the following day, 12/5/2014.

The preliminary integrated peak demand for hour-ending 18:00 on Thursday was 17,996 MW, 204 MW below the forecast 18,200 MW value.

New York


- 25,738 MW - Winter all-time peak load set January 7, 2014
- 24,737 MW - “1 in 2” Forecast Winter Peak for 2014-15
- 26,333 MW - “1 in 10” Forecast Winter Peak for 2014-15

The New York ISO met all operating reliability criteria over the Winter 2015 peak

- No need for state-wide Supplemental Capacity Commitments
- No need for Demand Response Notifications or Activations

January and February were both colder than the 10-year average and 30-year average. It was the coldest February for New York State since 1941 (74 years). The average temperature for February 2015 was 12 degrees below normal.

Statewide Supplemental Capacity Commitments
On February 18, 2015, the New York ISO committed Oswego 5 for reliability purposes all hours for February 19, 2015 following the forced outage of the Nine Mile 2 nuclear plant (1,310 MW) and 600 MW of other upstate gas-fired generation capacity.

Demand Response
On February 18, the New York ISO provided the 21-hour notification to Demand Response resources but an actual activation was not needed

Transmission Performance
Very few transmission forced outages during the Winter of 2015.

Fuel Inventories
Alternative oil fuel supplies were sufficient throughout most of the winter -- although supplies became tighter in mid to late February. The NYISO initiated the state-agency communication protocol on February 24, 2015 due to low inventory at one station

Regional Electric Conditions

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Fewer generator derates across neighboring regions were experienced; PJM set a new all-time winter peak of 143,800 MW on the morning of February 20, 2015.

Regional Pipeline Conditions
The majority of the Northeast interstate pipelines and LDCs issued Gas Alerts and Operational Flow Orders during most of the cold weather conditions during January and February.

Ontario
Electricity demand is shaped by a several factors which have differing impacts. These factors can be grouped into those that increase demand (population growth and economic expansion), those that reduce demand (conservation and embedded generation) and those that shift demand (time of use rates and the Industrial Conservation Initiative [ICI]). How each of these factors impacts electricity consumption varies by season and time of day.

December
- December was milder than normal. Monthly energy demand was 12.2 TWh and bumped up to 12.4 TWh after correcting for weather. Both values are low by historical standards for December.
- The peak occurred on December 2, which was the third coldest day of the month but was preceded by and followed by rather mild days. Therefore, the peak was a rather modest 20,938 MW (21,322 MW weather corrected). This was lower than last December but an increase over 2012. There was a “cold snap” later in the month but it occurred over the holiday period and therefore did not generate high peak demands.
- Wholesale customers’ capped off a negative quarter with consumption dropping by 1.4% compared to December 2013.

January
- The weather for January was colder than normal. Energy demand for the month was 13.1 TWh (12.8 TWh weather corrected) which is low by historical standards. The actual was the second lowest and the weather corrected the lowest January since market opening.
- Whereas the month was colder than normal, the peak temperature was just slightly colder than normal. The peak demand for the month was on the coldest day and was 21,814 MW (21,531 MW weather corrected). These are quite low by historical standards for January, but this year was different as the ICI significantly reduced the January peak. This was the first time that the ICI was “in play” during the winter. Wholesale customers’ consumption continued the weakness of the last quarter of 2014 into 2015. Year over year consumption fell by 3.2%.

February
- The weather for February was significantly colder than normal. Energy demand for the month was 12.3 TWh, the highest February since 2008. However, the weather corrected value was a much more modest 11.5 TWh, which is consistent with the relatively flat levels of demand since the recession.

26 See: http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2015mar.pdf
The peak for the month was 21,494 MW, which was lower than last year’s February peak. However, this year’s peak was significantly impacted by the ICI. The weather corrected value of 20,132 MW was low by historical standards, but that was partially due to the ICI impacts. The peak occurred on February 19th, which was the second coldest day of the month and during a course of a “cold snap”.

Wholesale customers’ consumption continued to decline, falling 4.7% compared to the previous February. That marked five consecutive months of contraction.

Overall, energy demand for the four months from November to February was down 2.1% compared with the same four months one year prior. After adjusting for the milder weather, demand for the four months showed much larger decline of 2.7%.

For the four months, wholesale customers’ consumption posted a 2.7% decrease over the same months a year prior with Pulp & Paper, Iron & Steel and Petroleum Products accounting for most of the reductions.

Ontario managed well despite a record cold February. Power system operations during the cold snap were well coordinated throughout the North East. Seasonal readiness testing was in place before the cold snap to ensure generators that had not run recently were exercised. Gas Electric Coordination enhancements resulted in better reporting of gas supply impacts on generators’ abilities to supply energy.
ANALYSIS
Winter 2015/16 Results

Base Case Scenario
Table 7 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) for November 2015 through March 2016 period for the Base Case assumptions for all NPCC Areas for the 2003/04 load shape assumptions.

Figure 4(a) shows the estimated use of operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) for the Base Case assumptions. The results indicate that only the Maritimes Area has a chance to use these procedures in response to a capacity deficiency.

Figure 4(b) shows the corresponding results for the extreme load (representing the second to highest load level, having approximately a 6% chance of being exceeded).

![Figure 4a](image)

Estimated Use of the Indicated Operating Procedures for Winter 2015/16
Base Case Assumptions - Expected Load Level
Base Case Assumptions

The following summary of Base Case assumptions represents system conditions consistent with those assumed in the NPCC CO-12 Working Group's "Reliability Assessment for Winter 2015-16", December 2015. The Base Case assumptions are summarized below:

**System**
- As-Is System for the 2015-2016 period
- Transfers allowed between Areas
- 2003/04 Load Shape adjusted to Area’s year 2015 forecast (expected & extreme assumptions)

**Ontario**
- Existing and planned generation resources modelled consistent with the 2015-Q2 18-Month Outlook (~ 36,411 MW)
- Capacity backed energy export of 500 MW to Québec for reliability for the period from December 1, 2015 to March 31, 2016

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27 The 2003/04 load shape represents a weather pattern that includes a consecutive period of cold days.
New England
Resource and load consistent with the 2015 CELT report data for winter 2015/2016:
- ~ 33,214 MW of existing and planned generation resources modeled
- ~ 2,285 MW of demand supply resources modeled
- ~ 1,326 MW of capacity import
- ~ 4,000 MW of gas-fired generation assumed unavailable

New York
- All cables in service
- Assumptions consistent with New York Installed Capacity Requirements for May 2015 through April 2016
- Load forecast and generation capacity data consistent with New York’s 2015 Gold Book data

Maritimes
- ~ 920 MW of installed wind generation (modeled using April 2011 to March 2012 hourly wind year excluding 164 MW of energy only units in Nova Scotia)
- no import/export contracts assumed
- 242 MW of demand response (interruptible load) available

Québec
- Resources and load forecast are consistent with the Québec 2014 Comprehensive Review of Resource Adequacy - including about 1,500 MW of scheduled maintenance and restrictions
- 3,350 MW of installed wind capacity (974 MW modeled representing 30% value at peak) and 104 MW derated 100%
- 1,800 MW of available capacity imports
- ~1,000 MW of firm capacity exports

PJM-RTO
- As-Is System for the 2015/16 winter period – consistent with the PJM 2014 Reserve Requirement Study 28
- 2003/04 Load Shapes adjusted to the 2015 forecast provided by PJM
- Load forecast uncertainty based on PJM 2014 Reserve Requirement Study
- Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)

RF ‘Other’ 29
- As-Is System for the 2015/16 winter period – based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff
- 2003/04 Load Shapes adjusted to the most recent monthly forecast provided by PJM
- Load forecast uncertainty provided by PJM
- Operating Reserve 2,206 MW (30-min. 1,470 MW; 10-min. 736 MW)

29 “RFC Other” refers to the RFC and SERC portions of MISO.
MRO-US  
- As-Is System for the 2015/16 winter period - based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff  
- 2003/04 Load Shapes adjusted to the most recent monthly forecast provided by PJM  
- Load forecast uncertainty provided by PJM  
- Operating Reserve 1,700 MW (30-min. 1,200 MW; 10-min. 500 MW)  

New York Details  
The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the New York ISO Report 9 - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2015 – 2016 Capability Year" , January 14, 2015 and New York State will meet the capacity requirements described in the “New York Control Area Installed Capacity Requirements for the Period May 2015 – April 2016” New York State Reliability Council, December 5, 2014 Technical Study Report. 10  

The New York unit ratings were based on the Dependable Maximum Net Capability (DMNC) values from the “2014 Load & Capacity Data of the NYISO” (Gold Book 31).  

Existing Resources  
All in-service New York generation resources were modeled.  

Wind Modeling  
Wind generators are modeled as hourly load modifiers. The output of each unit varies between 0 and the nameplate value based on 2013 wind production data. Characteristics of this data indicate a nominal winter capacity factor of 30% at the time of the winter peak hours. A total of 1,457 MW of installed capacity associated with wind generators is included in this study.  

Solar Modeling  
Solar generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate MW value based on solar data collected near the plant sites. Characteristics of this data indicate a less than 5% capacity factor during the winter peak hours. A total of 31.5 MW of solar capacity is included in this study.  

Special Case Resources and Emergency Demand Response Programs  
Special Case Resources (SCRs) are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs offer load curtailment as ICAP resources and provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. SCRs are required to  

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30 MRO-US refers to the MRO portion of MISO.  
respond to a deployment request for a minimum of four hours; however there is no limit to the number of calls or the time of day in which the Special Case Resources may be deployed. SCRs receive a capacity payment for load curtailment capability sold in the ICAP market and an energy payment for energy performance during a demand response event.

The Emergency Demand Response Program (EDRP) is a voluntary reliability program that allows registered interruptible loads and standby generators when activated in accordance with the NYISO Emergency Operating Manual. EDRP resources are only paid for their energy performance during a demand response event. There is no limit to the number of calls or the time of day in which EDRP resources may be deployed.

SCRs and EDRPs are modeled as an operating procedure step activated to minimize the probability of customer load disconnection. The GE-MARS models the NYISO operations practice of only activating operating procedures in zones from which are capable of being delivered.

For this study, 1,132 MW of SCRs were modeled. At the time of the winter peak, this amount was further discounted by 65% based on historical availability.

EDRPs are modeled as a 86 MW operating procedure step and are also limited to a maximum of five EDRP calls per month. This value is discounted based on actual experience from the forecast registered amount to 14 MW.

**New England Details**

The New England generating unit ratings were consistent with their winter seasonal capability to be reported for the 2015 CELT report. 32

**Demand Supply Resources**

The passive non-dispatchable demand resources, On-Peak and Seasonal-Peak, are expected to provide ~1,685 MW of load relief during the peak hours. About 600 MW of active demand resources, including Real-Time Demand Resources and Real-Time Emergency Generation Resources, provide additional real time peak load relief at a request by ISO New England, during or in anticipation of expected operable capacity shortage conditions, to implement ISO-NE Operating Procedure No. 4, Actions During a Capacity Deficiency. These demand resources are discounted in the assessment to account for performance based on the observed availability factors of demand response programs in the past.

**Ontario Details**

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the IESO “18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System From July 2015 to December 2016” (released June 22, 2015). 6

**Existing Resources**

All in-service Ontario generation resources were modeled.

Wind Modeling
For the purposes of this assessment, the IESO assumed that wind generation has a dependable contribution of 33.4% of the installed generation capacity at the time of peak for December, January, and February.

Solar Modeling
The IESO assumed that solar generation has no contribution at the time of peak for December, January, and February.

Demand Measures
The IESO assumed that the demand measures in Ontario total 555 MW to 720 MW for the winter period.

In addition, the study assumed 148 MW is available from Utility Surplus (a/k/a “Stretch” Capability) as a part of operating procedures.
Severe Case Scenario

Table 8 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during November 2015 through March 2016 period for the Severe Case Scenario for all NPCC Areas for the 2003/04 load shape assumptions, respectively. Only the Maritimes Area is expected to need to use these procedures in response to a capacity deficiency for this Scenario.

Figure 5(a) shows the estimated use of operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) for the Severe Case assumptions.

Figure 5(b) shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).
Severe Case Assumptions
The Severe Case Scenario assumptions are summarized below:

System
- As-Is System for the 2015/16 period
- Transfers allowed between Areas
- Transfer capability between NPCC and MRO/RFC- ‘Other’ reduced by 50%.
- 2003/04 Load Shape adjusted to Area’s year 2015 forecast (expected & extreme assumptions) 33

Ontario
- ~1,400 MW of maintenance extended into the winter period
- Hydroelectric capacity and energy 10% lower than the Base Case

New England
- Assume 50% reduction to the import capabilities of external ties
- Maintenance overrun by 4 weeks
- ~ 5,000 MW of gas-fired generation assumed unavailable

New York
- Extended Maintenance in southeastern New York (500 MW)
- 600 MW of assumed Cable transmission reduction across HVDC facilities
- 4,000 MW of generation assumed unavailable across fleet due to fuel delivery issues.

33 The 2003/04 load shape represents a weather pattern that includes a consecutive period of cold days.
Maritimes
- Available wind capacity (~920 MW nameplate) reduced by half for every hour in December, January and February to simulate icing conditions
- 50% natural gas capacity curtailment (264 MW) assumed to simulate a reduction in gas supply for December, January, and February (assuming dual fuel units revert to oil)

Québec
- ~1,000 MW reduction from the power generation system

PJM-RTO
- Gas-fired only capacity not having firm pipeline transportation, assumed ~6,400 MW unavailable
- One percentage point increase in load forecast uncertainty
- Ice Storm; ice blocking fuel delivery to all units. Unit outage event ~8,400 MW

Conclusions
As shown in Figure 4a, the use of operating procedures designed to mitigate resource shortages is not expected for Québec, the Maritimes, Ontario, New York, and New England under the assumed Base Case conditions for the expected load level. As shown in Figure 4b, only the Maritimes Areas show a minimal need for use of operating procedures in response to a capacity deficiency this winter under the Base Case, extreme load conditions.

The expected load level results were based on the probability-weighted average of the seven load levels simulated. The extreme load level represents the second to highest load level, having approximately a 6% chance of being exceeded.

As shown in Figures 5a and 5b the Maritimes Area, and to a lesser extent, New England show a need for use of operating procedures in response to a capacity deficiency this winter under the Severe Case conditions.
APPENDIX A

Objective and Scope of Work

1. Objective
On a consistent basis, evaluate the near term seasonal and long-range 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 2015 - 2020 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 2015 - 2020 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 2015 summer and November 2015 to March 2016 winter seasonal periods, 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 (2015 -2016) 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 each 2016 - 2020 calendar year, 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 of the long-range (2016-2020) analysis will be measured by calculating the annual Loss of Load Expectation (LOLE) for each NPCC Area.
and neighboring Regions for each calendar year. In addition, Loss of Load Hours (LOLH) and Expected Unserved Energy will also be similarly estimated for the NPCC Areas.

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2015.

A report of the results of the winter assessment will be published no later than September 30, 2015.

A report summarizing the results of the long-range overview will be published no later than December 31, 2015.
### APPENDIX B

Table 7 - Base Case Assumptions (2003/04 Load Shape Assumption)
Expected Need for Indicated Operating Procedures (days/period)
(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Québec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
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<td>30-min VR</td>
<td>30-min IL</td>
<td>10-min Appeal</td>
<td>30-min VR</td>
<td>10-min Appeal</td>
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<td>-</td>
<td>-</td>
<td>0.109</td>
<td>0.042</td>
</tr>
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</table>

| 03/04 Load Shape-Extreme Load | 30-min VR | 30-min IL | 10-min Appeal | 30-min VR | 10-min Appeal | Disc | 30-min VR | Appeal | 10-min Disc | 30-min VR | 10-min Disc | Disc |
| Nov | - | - | - | - | - | - | - | - | - | - | - | - |
| Dec | - | - | - | 0.044 | 0.015 | 0.001 | - | - | - | - | - | - | - | - | - | - |
| Jan | 0.001 | - | - | 0.498 | 0.225 | 0.015 | - | - | - | - | - | - | - | - | - | - |
| Feb | - | - | - | 0.110 | 0.028 | 0.001 | - | - | - | - | - | - | - | - | - | - |
| Mar | - | - | - | 0.138 | 0.046 | - | - | - | - | - | - | - | - | - | - | - |
| Nov-Mar | 0.001 | - | - | 0.790 | 0.314 | 0.017 | - | - | - | - | - | 0.001 | - | - | - | - |

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction ("IL" - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
## Appendix B

Table 8 - Severe Case Scenario (2003/04 Load Shape Assumption)
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Québec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min</td>
<td>10-min</td>
<td>Apl</td>
<td>Disc</td>
<td>30-min</td>
</tr>
<tr>
<td>03/04 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.022</td>
</tr>
<tr>
<td>Jan</td>
<td>0.022</td>
<td>0.003</td>
<td>-</td>
<td>-</td>
<td>0.905</td>
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<tr>
<td>Feb</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>0.180</td>
</tr>
<tr>
<td>Mar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.019</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.022</td>
<td>0.003</td>
<td>-</td>
<td>-</td>
<td>1.131</td>
</tr>
<tr>
<td>03/04 Load Shape-Extreme Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.263</td>
</tr>
<tr>
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<td>0.002</td>
<td>-</td>
<td>1.151</td>
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<tr>
<td>Feb</td>
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<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Mar</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>0.156</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.263</td>
<td>0.023</td>
<td>0.002</td>
<td>-</td>
<td>9.184</td>
</tr>
</tbody>
</table>

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction ("IL" - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
Multi-Area Reliability Simulation Program Description

General Electric’s Multi-Area Reliability Simulation (MARS) program allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique
A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

Reliability Indices
The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily Loss of Load Expectation (LOLE - days/year)
- Hourly LOLE (hours/year)
- Loss of Energy Expectation (LOEE - MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The Working Group used both the daily LOLE and Operating Procedure indices for this analysis.

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

See: http://ge-energyconsulting.com/practice-area/software-products/mars
APPENDIX C

Resource Allocation Among Areas
The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation
MARS has the capability to model the following different types of resources:
- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.
APPENDIX C

Thermal Unit
In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

\[ \text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}} \]

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units
Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A
APPENDIX C

Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration
MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM
Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System
The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts
Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.