Northeast Power Coordinating Council
Reliability Assessment
For
Summer 2015

FINAL REPORT
April 30, 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 SUMMER 2015 .......................................................................... 7
   SUMMARY OF RELIABILITY COORDINATOR AREA FORECASTS ..................................... 8

4. RESOURCE ADEQUACY .......................................................................................................... 13
   NPCC SUMMARY FOR SUMMER 2015 ..................................................................................... 13
   MARITIMES ............................................................................................................................ 14
   NEW ENGLAND ............................................................................................................. 15
   NEW YORK ..................................................................................................................... 16
   ONTARIO ........................................................................................................................ 18
   QUÉBEC .......................................................................................................................... 20
   GENERATION RESOURCE CHANGES ............................................................................. 23
   WIND CAPACITY ANALYSIS BY RELIABILITY COORDINATOR AREA ....................... 30

5. TRANSMISSION ADEQUACY ............................................................................................... 35
   INTER-REGIONAL TRANSMISSION ADEQUACY ................................................................ 35
   AREA TRANSMISSION ADEQUACY ASSESSMENT ............................................................ 37
   AREA TRANSMISSION OUTAGE ASSESSMENT ................................................................. 43

6. OPERATIONAL READINESS FOR 2015 .................................................................................. 46
   SUMMER 2015 SOLAR TERRESTRIAL DISPATCH FORECAST OF GEOMAGNETICALLY INDUCED CURRENT 53

7. POST-SEASONAL ASSESSMENT AND HISTORICAL REVIEW ............................................ 55
   SUMMER 2014 POST-SEASONAL ASSESSMENT ................................................................. 55

8. 2015 RELIABILITY ASSESSMENTS OF ADJACENT REGIONS ........................................... 58

9. CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT
   EXECUTIVE SUMMARY ....................................................................................................... 59

APPENDIX I – SUMMER 2015 EXPECTED LOAD AND CAPACITY FORECASTS ...................... 60
   TABLE AP-1 - NPCC SUMMARY ......................................................................................... 60
   TABLE AP-2 – MARITIMES ................................................................................................. 61
   TABLE AP-3 – NEW ENGLAND ......................................................................................... 62
   TABLE AP-4 – NEW YORK ............................................................................................... 63
   TABLE AP-5 – ONTARIO .................................................................................................... 63
   TABLE AP-5 – ONTARIO .................................................................................................... 64
   TABLE AP-6 – QUÉBEC ..................................................................................................... 65

APPENDIX II – LOAD AND CAPACITY TABLES DEFINITIONS ............................................. 66
APPENDIX III – SUMMARY OF TOTAL TRANSFER CAPABILITY UNDER FORECASTED SUMMER CONDITIONS........................................................................................................................................................................71

APPENDIX IV – DEMAND FORECAST METHODOLOGY .......................................................................................................................... 81

RELIABILITY COORDINATOR AREA METHODOLOGIES .................................................................................................................. 81

APPENDIX V - NPCC OPERATIONAL CRITERIA, AND PROCEDURES .................................................. 88

APPENDIX VI - WEB SITES........................................................................................................................................................................ 91

APPENDIX VII - REFERENCES................................................................................................................................................................. 92

APPENDIX VIII – CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION ........................................................................................................ 93
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.

The CO-12 Working Group members are:

- Michael Courchesne (Chair) - ISO New England
- Rod Hicks - New Brunswick Power – System Operator
- Kyle Ardolino - New York ISO
- Monique Chugh - Independent Electricity System Operator
- Mathieu Labbé - TransÉnergie
- Chris Milligan - Nova Scotia Power Inc.
- Paul Roman - Northeast Power Coordinating Council
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 Summer Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the summer 2014\(^1\).

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 forecasted coincident peak demand for NPCC during the peak week (week beginning July 5, 2015)\(^2\) is 107,440 MW, as compared to 107,341 MW forecasted during the summer 2014 peak week. The coincident peak demand during the summer of 2014 was 96,068 MW, occurring on July 1. The capacity outlook indicates a forecasted Net Margin for that week of 14,154 MW. This equates to a net margin of 13.2 percent in terms of the 107,440 MW forecasted peak demand. The week with the minimum forecasted Net Margin of 9,007 MW available to NPCC is the week beginning June 28, 2015.

- The largest forecasted NPCC Net Margin of 38.3 percent occurs during the week beginning May 17, 2015.

---

\(^1\) The 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, ISO-NE, NYISO, IESO, and HQ are included in Appendix I.
- During the NPCC forecasted peak week of July 5, 2015, the Area forecasted net margins in terms of forecasted demand ranges from approximately 3.8 percent in New England to 68.5 percent in the Maritimes.

- When comparing the peak week from last summer (July 6, 2014) to this summer’s expected peak week (July 5, 2015) the NPCC installed capacity has increased by 3,422 MW. Individual area changes are the following: Maritimes, +204; New England, -571 MW; New York, +717 MW; Ontario, +1,782 MW; and Québec, +1,290 MW.

- 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 summer 2015 peak demand of 3,748 MW for the week beginning April 26 with a projected net margin of 1,201 MW (32 percent). When compared to the summer 2014 peak demand forecast it is an increase of 10 MW (0.03 percent). The transfer capabilities between New Brunswick and New England are expected to be fully available during the summer assessment period. There is annual maintenance scheduled on the Eel River HVDC during one week in May and one week in June, one circuit at a time, which will lower the transfer capability between New Brunswick and Québec. This maintenance is scheduled to be completed prior to the forecasted NPCC summer peak.

- New England forecasts a summer peak demand of 26,710 MW for the week beginning July 19, 2015 with a projected net margin of 1,016 MW (3.8 percent). This summer 2015 peak demand forecast is 52 MW (0.19 percent) more than the summer 2014 peak demand forecast of 26,658 MW. The forecast takes into account the demand reductions associated with energy efficiency, load management and distributed generation. The New England summer 2014 actual peak load of 24,443 MW occurred on July 2 at HE 15 EDT. The summer 2015 forecast is based on updated historical load, weather data and an updated economic forecast, which indicates slower growth entering into 2015 than the previous economic forecast. Short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system are not included in the provided margins.

---

3 Load Forecast assumes Peak Load Exposure of 26,710 MW, to be reported in the 2015 CELT Report and does include a Passive Demand Response adjustment of 1,685 MW. The most recent copy of the celt report can be found at http://www.iso-ne.com/system-planning/system-plans-studies/celt
The NYISO anticipates adequate resources to meet demand for the summer 2015 season. The current summer 2015 peak forecast is 33,567 MW and was updated in December, 2014. It is lower than the previous year’s forecast by 99 MW (0.29 percent), which is mainly attributed to a decrease in upstate industrial load. Anticipated net margins for the summer peak period (June through August) range from 1,553 MW to 2,026 MW (4.6 to 6.0 percent) respectively.

The IESO anticipates adequate resources to meet demand for the summer 2015 period. The forecasted Ontario summer peak is 22,991 MW for week beginning July 5, 2015. The forecast includes the reductions due to conservation measures, growth in embedded solar and wind generation and pricing factors. The forecasted minimum net margin is 1,372 MW, or 6 percent during the week beginning June 28, 2015. Ontario 2014 summer peak demand forecast was 23,025 MW (normal weather) 24,958 MW (extreme weather). The 2015 summer forecast is 34 MW lower than the 2014 summer forecast. A similar extreme peak of 24,814 MW is forecasted for summer 2015. Ontario’s grid supplied energy demand is expected to remain relatively flat in 2015 with on-going conservation initiatives reducing the need for bulk power system electricity. Economic and population growth is also mitigated by increased embedded generation. The current amount of embedded solar and wind resources is approximately 1,600 MW and 500 MW, respectively.

The Québec Area forecasted summer peak demand (excluding April, May and September) is 21,090 MW during the week beginning August 9, with a forecasted net margin of 7,159 MW. For summer 2015, Installed Capacity will total 44,813 MW for the Québec Area. Since last summer, La Romaine 2 (capable of providing 640 MW) has been commissioned as well as 482 MW of new wind generation. Hydro and biomass generation adjustments have also increased the Installed Capacity by 168 MW. No particular resource adequacy problems are forecasted and Québec area expects to be able to provide assistance to other areas if needed, up to the transfer capability available. Following the disturbance event that occurred on July 3, 2013, system limits are now adjusted according to the intensity of forests fires when they occur.

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

---

4 Nameplate values.
the Summer 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 Summer Operating Period the CO-12 Working Group:

- Examined historical summer 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. The NPCC CP-8 Working Group has done a probabilistic assessment of the implementation of operating procedures for the 2015 Summer 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 may include temperature variations, wind generation capacity, in-service delays of new generation, load forecast uncertainties, evolving load response measures, fuel availability, system voltage and generator reactive capability limits.
- Reviewed the capacity margins for normal and extreme system load 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.

---

5 For the purpose of this report, the Summer Operating Period evaluation will include operating conditions from week beginning April 26, 2015 through the week beginning September 13, 2015.
• Coordinated with other parallel seasonal operational assessments including the Eastern Interconnection Reliability Assessment Group (ERAG) and the NERC Reliability Assessment Subcommittee (RAS) Seasonal Assessments.
3. Demand Forecasts for Summer 2015

The non-coincident forecasted peak demand for NPCC over the 2015 Summer Operating Period is 108,106 MW. This peak demand translates to a coincident peak demand of 107,440 MW which is expected during the week beginning July 5, 2015. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

Ambient weather conditions are the single most important variable impacting the demand forecasts during the summer months. As a result, each Reliability Coordinator area is aware that the summer peak demand could occur during any week of the summer period as a result of these weather variables. Historically the peak demands and temperatures between New England and New York can have a high degree of correlation due to the relative locations of their respective load centers. Depending upon the extent of the weather system and duration, there is potential for the Ontario peak demand to be coincident with New England and New York. It should also be noted that the non-coincident peak demand calculation is impacted primarily by the fact that the Maritimes and Québec experience late spring demands influenced by heating loads that occur during the defined Summer Operating Period.

The impact of ambient weather conditions on load forecasts can be demonstrated by various means. The Maritimes and Ontario represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. 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 above 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. New England relates air temperature to the load response and increases the load by a MW factor for each degree above the base value.

While the peak demands appear to be confined to the operating weeks in late June through July, each Area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and / or higher than normal outage rates.

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

- Summer 2015 Forecasted Peak: 3,748 MW (normal) and 4,025 MW (extreme), week beginning April 26, 2015
- Summer 2014 Forecasted Peak: 3,738 MW, week beginning April 27, 2014
- Summer 2014 Actual Peak: 3,721 MW, on April 30, 2014 at HE8 EDT

Figure 1: Maritimes Summer 2015 Weekly Demand Profile
New England

- Summer 2015 Forecasted Peak: 26,710 MW (normal) and 29,060 MW (extreme), week beginning July 19, 2015
- Summer 2014 Forecasted Peak: 26,658 MW (normal) and 28,963 MW (extreme), week beginning July 6, 2014
- Summer 2014 Actual Peak: 24,443 MW, on July 2, 2014 at HE15 EDT

Figure 2: New England Summer 2015 Weekly Demand Profile
New York

- Summer 2015 Forecasted Peak: 33,567 MW (normal) and 35,862 MW (extreme) during the months of June through August, 2015
- Summer 2014 Forecasted Peak: 33,666 MW (normal) and 35,976 MW (extreme) during the months of June through August, 2014
- Summer 2014 Actual Peak: 29,782 MW on September 2, 2014 at HE16 EDT

Figure 3: New York Summer 2015 Weekly Demand Profile
Ontario

- Summer 2015 Forecasted Peak: 22,991 MW (normal) and 24,814 (extreme), week beginning July 5, 2015
- Summer 2014 Forecasted Peak: 23,025 MW (normal) and 24,958 (extreme), week beginning July 6, 2014
- Summer 2014 Actual Peak: 21,363 MW, on August 26, 2014 at HE17 EST

**Figure 4: Ontario Summer 2015 Weekly Demand Profile**
Québec

- Summer 2015 Forecasted Peak: 21,090 MW, (normal) and 21,936 MW (extreme) week beginning August 9, 2015
- Summer 2014 Forecasted Peak: 21,113 MW, (normal) and 21,518 MW (extreme) week beginning June 15, 2014
- Summer 2014 Actual Peak: 21,165 MW, on August 26, 2014 at 18h00 EST

Figure 5: Québec Summer 2015 Weekly Demand Profile
4. **Resource Adequacy**

**NPCC Summary for Summer 2015**

The assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning July 5, 2015 (107,440 MW). Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

Table AP-1, Appendix I reflect the NPCC normal load and capacity summary for the 2015 Summer Operating Period. Appendix I, Tables AP-2 through AP-6, contain the normal load forecast and capacity summary for each NPCC Reliability Coordinator area.

Each entry in Table 1 is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator Areas. Table 1 summarizes the load and capacity situation for the peak week beginning July 5, 2015 compared to the Summer 2014 forecasted peak week (week beginning July 6, 2014).

**Table 1: Comparison of Resource Adequacy between the Summer 2015 and 2014 Forecasts**

<table>
<thead>
<tr>
<th>All values in MW</th>
<th>2015 Forecast</th>
<th>2014 Forecast</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>157,112</td>
<td>153,690</td>
<td>3,422</td>
</tr>
<tr>
<td>*Net Interchange with areas outside NPCC</td>
<td>1,695</td>
<td>832</td>
<td>863</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>158,807</td>
<td>154,522</td>
<td>4,285</td>
</tr>
<tr>
<td>Demand</td>
<td>107,440</td>
<td>107,341</td>
<td>99</td>
</tr>
<tr>
<td>Interruptible load</td>
<td>2,762</td>
<td>2,803</td>
<td>-41</td>
</tr>
<tr>
<td>Maintenance/De-rate</td>
<td>23,724</td>
<td>21,496</td>
<td>2,228</td>
</tr>
<tr>
<td>Required Reserve</td>
<td>8,238</td>
<td>7,932</td>
<td>306</td>
</tr>
<tr>
<td>Unplanned Outages</td>
<td>8,013</td>
<td>8,173</td>
<td>-160</td>
</tr>
<tr>
<td>Net Margin</td>
<td>14,154</td>
<td>12,383</td>
<td>1,771</td>
</tr>
<tr>
<td>Bottled Capacity QC/Maritimes to NPCC</td>
<td>3,606</td>
<td>3,391</td>
<td>215</td>
</tr>
<tr>
<td><strong>Revised Net Margin</strong></td>
<td><strong>10,548</strong></td>
<td><strong>8,992</strong></td>
<td><strong>1,556</strong></td>
</tr>
<tr>
<td>Week Beginning</td>
<td>5-Jul-15</td>
<td>6-Jul-14</td>
<td>-</td>
</tr>
</tbody>
</table>
The Revised Net Margin for the 2015 summer capacity period is a 1,556 MW increase from the previous summer. This adjustment is largely attributed to the increased installed capacity total for the NPCC area as well as expected transfers into the NPCC region. The following sections detail the summer 2015 capacity analysis for each Reliability Coordinator area and the NPCC region.

**Maritimes**

The Maritimes Area declared installed capacity is scheduled to be operational for the summer period; the net margins calculated include derates for variable generation (wind and hydro flows), ambient temperatures and scheduled out-of-service generation. Imports into the Maritimes Area are not included unless they have been confirmed 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 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.
New England

New England conducts an Installed capacity and Operable capacity assessment comparison recognizing Normal Load forecasts to determine New England capacity risks. For example, some of these risks can be identified as threats to fuel deliverability for natural gas-fired generation during pipeline maintenance and the comparison of a generator’s Seasonal Claimed Capability (SCC) value against their Capacity Supply Obligation (CSO). The CSO is a generator’s obligation to satisfy New England’s Installed Capacity Requirement (ICR) through a Forward Capacity Auction (FCA) and the SCC is recognized as a generator’s maximum output established through seasonal audits and reflected as capacity throughout this report, utilized in Table 1, Table 1.1, Table 1.2 and Appendix 1; AP-1 and AP-3 Tables.

<table>
<thead>
<tr>
<th>Normal Load Forecast</th>
<th>19-Jul-2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSO</td>
</tr>
<tr>
<td>Operable Capacity + Non Commercial Capacity MW</td>
<td>29,576</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>1,237</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>30,813</strong></td>
</tr>
<tr>
<td>Peak Normal Load Forecast MW</td>
<td>26,710</td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>638</td>
</tr>
<tr>
<td>Known Maintenance + Derates (-)</td>
<td>0</td>
</tr>
<tr>
<td>Operating Reserve Requirement MW (-)</td>
<td>2,375</td>
</tr>
<tr>
<td>Unplanned Outages and Gas at Risk(-)</td>
<td>2,100</td>
</tr>
<tr>
<td><strong>Operable Capacity Margin MW</strong></td>
<td><strong>266</strong></td>
</tr>
<tr>
<td><strong>Operable Capacity Margin %</strong></td>
<td><strong>1.0%</strong></td>
</tr>
</tbody>
</table>

Furthermore, New England performs an Installed capacity and Operable capacity assessment comparison recognizing extreme load forecasts to further evaluate New England capacity risks. This broadened approach helps identify potential capacity concerns for the upcoming capacity period and prepare for severe demand conditions. This analysis Table 1.2 below shows the further reduction in Operable Capacity Margin recognizing these factors. If extreme summer forecast conditions materialize and generators do not achieve SCC, New England will need to rely more heavily on import
capabilities from neighboring Areas as well as an increased likelihood of implementing emergency operating procedures to maintain system reliability.

Table 1.2: New England Installed and Operable Capacity for Extreme Forecast

<table>
<thead>
<tr>
<th>Extreme Load Forecast</th>
<th>19-Jul-2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSO</td>
</tr>
<tr>
<td>Operable Capacity + Non Commercial Capacity MW</td>
<td>29,576</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>1,237</td>
</tr>
<tr>
<td>Total Capacity</td>
<td><strong>30,813</strong></td>
</tr>
<tr>
<td>Peak Extreme Load Forecast MW</td>
<td>29,060</td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>638</td>
</tr>
<tr>
<td>Known Maintenance + Derates (-)</td>
<td>0</td>
</tr>
<tr>
<td>Operating Reserve Requirement MW (-)</td>
<td>2,375</td>
</tr>
<tr>
<td>Unplanned Outages and Gas at Risk(-)</td>
<td>2,100</td>
</tr>
<tr>
<td>Operable Capacity Margin MW</td>
<td>-2,084</td>
</tr>
<tr>
<td>Operable Capacity Margin %</td>
<td>-7.2%</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 Unforced Capacity Deliverability Rights (UDR) which is capacity provided by controllable transmission projects that provide a transmission interface to the NYCA. Interruptible Load includes Emergency Demand Response Programs and Special Case Resources. 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 Operating Reserve Requirement for New York is one-and-a-half times the largest single generating source contingency in the NYCA. 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 include those due to weather and availability of fuel.

The values in Table 1.3 are anticipated quantities as of the time of publishing this report. Finalized values are available in the NYISO Load & Capacity Data “Gold Book” published annually in late April.

Table 1.3: New York Operable Capacity Forecast

<table>
<thead>
<tr>
<th></th>
<th>Summer 2015</th>
<th>Normal Forecast</th>
<th>Extreme Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Installed Capacity</strong></td>
<td></td>
<td>38,700</td>
<td>38,700</td>
</tr>
<tr>
<td><strong>Net Interchange</strong></td>
<td></td>
<td>2,522</td>
<td>2,522</td>
</tr>
<tr>
<td><strong>Demand Response</strong></td>
<td></td>
<td>1,210</td>
<td>1,210</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td></td>
<td>41,222</td>
<td>41,222</td>
</tr>
<tr>
<td><strong>Known Maintenance &amp; Derates</strong></td>
<td></td>
<td>1,899</td>
<td>1,899</td>
</tr>
<tr>
<td><strong>Operating Reserve Requirement</strong></td>
<td></td>
<td>1,965</td>
<td>1,965</td>
</tr>
<tr>
<td><strong>Unplanned Outages</strong></td>
<td></td>
<td>3,016</td>
<td>3,016</td>
</tr>
<tr>
<td><strong>Peak Load Forecast</strong></td>
<td></td>
<td>33,567</td>
<td>35,862</td>
</tr>
<tr>
<td><strong>Operating Margin (MW)</strong></td>
<td></td>
<td>1,986</td>
<td>-309</td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td></td>
<td>5.9%</td>
<td>-0.9%</td>
</tr>
</tbody>
</table>
Ontario

Looking beyond the winter assessment period, considering existing and planned capacity coming in-service, the Ontario reserve requirement is met for the spring and summer months of 2015 under normal weather conditions, as indicated in Table 1.4.

Table 1.4: Ontario Operable Capacity Forecast

<table>
<thead>
<tr>
<th></th>
<th>Summer 2015</th>
<th>Normal Forecast</th>
<th>Extreme Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Installed Capacity</strong></td>
<td>35,547</td>
<td>35,547</td>
<td></td>
</tr>
<tr>
<td><strong>Net Interchange</strong></td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td><strong>Demand Response</strong></td>
<td>859</td>
<td>859</td>
<td></td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td>35,547</td>
<td>35,547</td>
<td></td>
</tr>
<tr>
<td><strong>Known Maintenance &amp; Derates</strong></td>
<td>7,852</td>
<td>7,852</td>
<td></td>
</tr>
<tr>
<td><strong>Operating Reserve Requirement</strong></td>
<td>1,664</td>
<td>1,664</td>
<td></td>
</tr>
<tr>
<td><strong>Unplanned Outages</strong></td>
<td>1,419</td>
<td>1,419</td>
<td></td>
</tr>
<tr>
<td><strong>Peak Load Forecast</strong></td>
<td>22,991</td>
<td>24,814</td>
<td></td>
</tr>
<tr>
<td><strong>Operating Margin (MW)</strong></td>
<td>2,212</td>
<td>389</td>
<td></td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td>9.6%</td>
<td>1.6%</td>
<td></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 1.4 indicate that occurrences of unserved energy are not expected over the summer 2015 period. Based on these results it is anticipated that Ontario will be energy adequate for the normal weather scenario for the review period.

Table 1.5: 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>May 2015</td>
<td>18,442</td>
<td>10,636</td>
</tr>
<tr>
<td>June 2015</td>
<td>18,161</td>
<td>11,467</td>
</tr>
<tr>
<td>July 2015</td>
<td>18,652</td>
<td>12,269</td>
</tr>
<tr>
<td>Aug 2015</td>
<td>18,070</td>
<td>11,926</td>
</tr>
<tr>
<td>Sept 2015</td>
<td>16,733</td>
<td>10,633</td>
</tr>
</tbody>
</table>
Québec

The Québec area anticipates adequate resources to meet demand for the 2015 summer season. The current 2015 peak forecast is 21,090 MW and the forecasted operating margin is 7,159 MW for the peak week. This includes known maintenance and derates of 11,795 MW, including scheduled generator maintenance and hydraulic as well as mechanical restrictions and wind generation derating. The following table shows the factors included in the operating margin calculation.

Table 1.6: Adequacy projections for Summer 2015

<table>
<thead>
<tr>
<th>Summer 2015</th>
<th>Normal Load Forecast (MW)</th>
<th>Extreme Load Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>44,813</td>
<td>44,813</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>-2069</td>
<td>-2069</td>
</tr>
<tr>
<td>Demand Response (+)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>42,744</td>
<td>42,744</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>-11,795</td>
<td>-11,795</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>-1,500</td>
<td>-1,500</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>-1,200</td>
<td>-1,200</td>
</tr>
<tr>
<td>Peak Load Forecast</td>
<td>21,090</td>
<td>21,936</td>
</tr>
<tr>
<td><strong>Operating Margin</strong></td>
<td><strong>7,159</strong></td>
<td><strong>6,313</strong></td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td><strong>34%</strong></td>
<td><strong>29%</strong></td>
</tr>
</tbody>
</table>

Energy adequacy assessment

Québec area's 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 a few consecutive dry years may require some operating measures 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 should 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.  

The table below summarizes projected capacity and margins by Reliability Coordinator area. Appendix I shows these projections for the entire summer operation period.

Table 2: Summary of Projected Capacity by Reliability Coordinator

<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>Interrupt. Load MW</th>
<th>Known Maint./ Derat. MW</th>
<th>Required Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPCC</td>
<td>NPCC Peak Week</td>
<td>5-Jul-15</td>
<td>157,112</td>
<td>1,695</td>
<td>158,807</td>
<td>107,440</td>
<td>2,762</td>
<td>23,724</td>
<td>8,238</td>
<td>8,013</td>
<td>14,154</td>
</tr>
<tr>
<td>Maritimes</td>
<td>Area Peak Week</td>
<td>26-Apr-15</td>
<td>7,695</td>
<td>0</td>
<td>7,695</td>
<td>3,748</td>
<td>312</td>
<td>2,048</td>
<td>734</td>
<td>276</td>
<td>1,201</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>26-Apr-15</td>
<td>7,695</td>
<td>0</td>
<td>7,695</td>
<td>3,748</td>
<td>312</td>
<td>2,048</td>
<td>734</td>
<td>276</td>
<td>1,201</td>
</tr>
<tr>
<td>NPCC Peak</td>
<td>5-Jul-15</td>
<td></td>
<td>7,726</td>
<td>0</td>
<td>7,726</td>
<td>3,213</td>
<td>323</td>
<td>1,674</td>
<td>734</td>
<td>278</td>
<td>2,150</td>
</tr>
<tr>
<td>New England</td>
<td>Area Peak Week</td>
<td>31-May-15</td>
<td>30,326</td>
<td>1,283</td>
<td>31,563</td>
<td>26,710</td>
<td>638</td>
<td>0</td>
<td>2,375</td>
<td>2,800</td>
<td>316</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>31-May-15</td>
<td>30,326</td>
<td>1,237</td>
<td>31,563</td>
<td>26,710</td>
<td>638</td>
<td>0</td>
<td>2,375</td>
<td>2,800</td>
<td>316</td>
</tr>
<tr>
<td>NPCC Peak</td>
<td>Week</td>
<td>5-Jul-15</td>
<td>30,326</td>
<td>1,237</td>
<td>31,563</td>
<td>26,710</td>
<td>638</td>
<td>0</td>
<td>2,375</td>
<td>2,100</td>
<td>1,016</td>
</tr>
<tr>
<td>New York</td>
<td>Area Peak Week</td>
<td>31-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>2,352</td>
<td>1,965</td>
<td>2,995</td>
<td>1,553</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>31-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>2,352</td>
<td>1,965</td>
<td>2,995</td>
<td>1,553</td>
</tr>
<tr>
<td>NPCC Peak</td>
<td>Week</td>
<td>5-Jul-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,899</td>
<td>1,965</td>
<td>3,016</td>
<td>1,985</td>
</tr>
<tr>
<td>Ontario</td>
<td>Area Peak Week</td>
<td>5-Jul-15</td>
<td>35,547</td>
<td>0</td>
<td>35,547</td>
<td>22,991</td>
<td>591</td>
<td>7,852</td>
<td>1,664</td>
<td>1,419</td>
<td>2,212</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>28-Jun-15</td>
<td>35,251</td>
<td>0</td>
<td>35,251</td>
<td>22,506</td>
<td>591</td>
<td>8,768</td>
<td>1,664</td>
<td>1,532</td>
<td>1,372</td>
</tr>
<tr>
<td>NPCC Peak</td>
<td>Week</td>
<td>5-Jul-15</td>
<td>35,547</td>
<td>0</td>
<td>35,547</td>
<td>22,991</td>
<td>591</td>
<td>7,852</td>
<td>1,664</td>
<td>1,419</td>
<td>2,212</td>
</tr>
<tr>
<td>Québec</td>
<td>Area Peak Week</td>
<td>26-Apr-15</td>
<td>44,813</td>
<td>-1,708</td>
<td>43,105</td>
<td>21,899</td>
<td>0</td>
<td>12,493</td>
<td>1,500</td>
<td>1,200</td>
<td>6,013</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>26-Apr-15</td>
<td>44,813</td>
<td>-1,708</td>
<td>43,105</td>
<td>21,899</td>
<td>0</td>
<td>12,493</td>
<td>1,500</td>
<td>1,200</td>
<td>6,013</td>
</tr>
<tr>
<td>NPCC Peak</td>
<td>Week</td>
<td>5-Jul-15</td>
<td>44,813</td>
<td>-2,064</td>
<td>42,749</td>
<td>20,959</td>
<td>0</td>
<td>12,299</td>
<td>1,500</td>
<td>1,200</td>
<td>6,791</td>
</tr>
</tbody>
</table>
### Generation Resource Changes

The following Table lists the recent and anticipated generation resource additions and retirements.

#### Table 3: Generation Resource Changes Summer 2014 through Summer 2015

<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>South Canoe</td>
<td>102</td>
<td>Wind</td>
<td>Q2 - 2015</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>COMFIT</td>
<td>3.4</td>
<td>Biomass</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>COMFIT</td>
<td>56.6</td>
<td>Wind</td>
<td>Various times 2015</td>
</tr>
<tr>
<td></td>
<td>COMFIT</td>
<td>41.4</td>
<td>Wind</td>
<td>Various times 2014</td>
</tr>
<tr>
<td></td>
<td>COMFIT</td>
<td>0.8</td>
<td>Biomass</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>218</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>De-rate</td>
<td>13</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Retirement</td>
<td>1</td>
<td>Diesel</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>204</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>Saddleback Ridge Wind</td>
<td>33</td>
<td>Wind</td>
<td>Q3 - 2014</td>
</tr>
<tr>
<td></td>
<td>Bucksport 3</td>
<td>87</td>
<td>Wood</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Total Retirement</td>
<td>-615</td>
<td>Nuclear</td>
<td>Q4 – 2014</td>
</tr>
<tr>
<td></td>
<td>Total Derate</td>
<td>-76</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>120</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>-571</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></td>
<td>Danskammer (repower)</td>
<td>532</td>
<td>Nat. Gas</td>
<td>Q4 – 2014</td>
</tr>
<tr>
<td></td>
<td>Binghamton Cogen (return-to-service)</td>
<td>48</td>
<td>Oil</td>
<td>Q4 – 2014</td>
</tr>
<tr>
<td></td>
<td>Ravenswood GT 3-3 (mothball)</td>
<td>-43</td>
<td>Nat. Gas</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Marsh Hill Wind</td>
<td>16</td>
<td>Wind</td>
<td>Q4 – 2014</td>
</tr>
<tr>
<td></td>
<td>Astoria 20 (return-to-service)</td>
<td>180</td>
<td>Oil/Nat. Gas</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Total DMNC Adjustments</td>
<td>-58</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>775</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>717</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>Nuclear adjustments</td>
<td>31</td>
<td>Nuclear</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Liskeard</td>
<td>30</td>
<td>Solar</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Smoky Falls G1, G2 &amp; G3</td>
<td>264</td>
<td>Hydro</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Blake Wind Farm</td>
<td>60</td>
<td>Wind</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Kipling Unit 3</td>
<td>79</td>
<td>Hydro</td>
<td>Q4 - 2014</td>
</tr>
<tr>
<td></td>
<td>Silvercreek Solar Park</td>
<td>10</td>
<td>Solar</td>
<td>Q1 - 2015</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>Thunder Bay Condensing Turbine Project</td>
<td>40</td>
<td>Biomass</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>74</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Grand Renewable Energy Park</td>
<td>149</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Abitibi</td>
<td>10</td>
<td>Solar</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Empire</td>
<td>10</td>
<td>Solar</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Northland Power Solar Long Lake</td>
<td>10</td>
<td>Solar</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Twin Falls</td>
<td>5</td>
<td>Hydro</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Adelaide Wind Power Project</td>
<td>40</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Goshen Wind Energy Centre</td>
<td>102</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Dufferin Wind Farm</td>
<td>100</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Jericho Wind Energy Centre</td>
<td>150</td>
<td>Wind</td>
<td>Q1 - 2015</td>
</tr>
<tr>
<td></td>
<td>Goulais Wind Farm</td>
<td>25</td>
<td>Wind</td>
<td>Q2 - 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>Bow Lake Phase 1</td>
<td>20</td>
<td>Wind</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>K2 Wind Project</td>
<td>270</td>
<td>Wind</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>High Falls Hydropower Development</td>
<td>5</td>
<td>Hydro</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Green Electron Power Plant</td>
<td>298</td>
<td>Gas</td>
<td>Q3 - 2015</td>
</tr>
<tr>
<td></td>
<td>Total Retirement</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Generation Adjustments</td>
<td>-323</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>2,105</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>1,782</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>Québec</td>
<td>La Romaine-2</td>
<td>640</td>
<td>Hydro</td>
<td>Q4 2014</td>
</tr>
<tr>
<td></td>
<td>Upgrade at Manic-2 Power Plant</td>
<td>30</td>
<td>Hydro</td>
<td>Q1 2015</td>
</tr>
<tr>
<td></td>
<td>Wind Additions</td>
<td>482</td>
<td>Wind</td>
<td>Q4 2014</td>
</tr>
<tr>
<td></td>
<td>Private Producers Adjustments</td>
<td>-7</td>
<td>Biomass</td>
<td>Q2-2015</td>
</tr>
<tr>
<td></td>
<td>Generation Adjustments</td>
<td>145</td>
<td>Hydro</td>
<td>Q2 2015</td>
</tr>
<tr>
<td></td>
<td>Total Retirement</td>
<td>-7</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Addition</td>
<td>1297</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Total</td>
<td>1290</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Maritimes**

There are generation projects of new capacity scheduled to be put in service during this summer assessment period that total 162 MW. The additions include two wind projects that total 158.6 MW and a 3.4 MW biomass project. All of these new additions are scheduled to be in service by September 6, 2015.

**New England**

New generation improvements include one wind project (Saddle Back Ridge) with a nameplate totaling 34 MW and a 87 MW wood/wood refuse generator (Bucksport 3) that became commercial in New England prior to the summer 2015 Operating Period. Significant retirements include the Vermont Yankee Nuclear generating facility that was capable of providing 615 MW of capacity.

**New York**

Since the summer 2014 season, several changes to generation in New York have occurred. The Danskammer plant (532 MW nameplate) has been repowered and is now fueled by natural gas and oil instead of coal. In addition, Ravenswood GT 3-4 (natural gas), Binghamton Cogen (natural gas/oil), and Astoria 2 (natural gas/oil) have returned to service, totaling 270 MW nameplate. A new 16 MW nameplate wind farm was also added, however this unit will not participate in the ICAP market. An additional 10 MW of wind power is expected to come in-service over the summer. The Ravenswood GT 3-3 (43 MW nameplate) was mothballed. Nameplate changes since the summer 2014 total +775 MW. This compares with a net increase in Installed Capacity of +717 MW which is based on Demonstrated Maximum Net Capability of participating units.
Ontario

By the end of the summer 2015 assessment period, the total capacity in Ontario is expected to increase by 1,782 MW compared to the end of the 2014 summer assessment period. This includes an increase of 1,050 MW of wind, 180 MW of solar, 353 MW of hydroelectric, 298 MW of natural gas and 193 MW of biomass resources. With the exception of the Green Electron Power Plant, all new resources are expected to be installed and become commercial before the NPCC forecasted peak week.

Québec

For the summer 2015 Assessment, nameplate wind capacity of the Québec area has reached 2,881 MW, a 482 MW increase since the last summer assessment. La Romaine-2 Hydro Generating Station (640 MW) has been successfully commissioned at the end of 2014. As the Québec area is winter peaking, generation projects’ commissioning is usually scheduled during autumn in preparation for the following winter peak period.
Fuel Infrastructure by Reliability Coordinator area

The following figures depict installed generation resource profiles for each Reliability Coordinator area and for the NPCC Region by fuel supply infrastructure.

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

NPCC Installed Capacity Profiles

- Hydro/Tidal: 31.7%
- Nuclear: 14.7%
- Gas: 14.4%
- Dual Fuel: 13.8%
- Oil: 8.9%
- Coal: 6.5%
- Wind: 6.3%
- Other: 3.6%
**Wind Capacity Analysis by Reliability Coordinator area**

For the 2015 Summer Operating Period, installed wind capacity accounts for approximately 6.4 percent of the total NPCC Installed Capacity during the coincident peak load. After applying adequate derate factors, the amount of wind generation counted towards capacity is less than 1 percent. Reliability Coordinator areas have distinct methods of accounting for this generation. The Reliability Coordinator areas are continuing to develop their knowledge regarding the operation of wind generation in terms of capacity forecasting and utilization factor.

The table below illustrates the nameplate wind capacity in NPCC for the 2015 Summer Operating Period. The Maritimes, Ontario, New York and Québec areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. New England reduces the nameplate capacity and includes this reduced capacity directly in the Installed Capacity section of the Load and Capacity Table. Please refer to Appendix V, Table APV-1 for information on the derating methodology used by each of the NPCC Reliability Coordinators.

<table>
<thead>
<tr>
<th>Reliability Coordinator area</th>
<th>Nameplate Capacity Summer 2015 (MW)</th>
<th>Capacity After Applied Derating Factor (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes**</td>
<td>1,087</td>
<td>191</td>
</tr>
<tr>
<td>New England</td>
<td>784</td>
<td>92</td>
</tr>
<tr>
<td>New York*</td>
<td>1,466</td>
<td>223</td>
</tr>
<tr>
<td>Ontario</td>
<td>3,532</td>
<td>282</td>
</tr>
<tr>
<td>Québec</td>
<td>2,881</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>9,750</td>
<td>788</td>
</tr>
</tbody>
</table>

*Total nameplate capacity in New York is 1,749 MW, however, only 1,466 MW participate in the ICAP market.

**Maritimes nameplate capacity is the total expected in-service by September 6, 2015.
Demand Response Programs

Each Reliability Coordinator area utilizes various methods of demand management. The table below summarizes demand response available within the NPCC area.

### Table 5: Summary of Active Demand Response Programs

<table>
<thead>
<tr>
<th>Reliability Coordinator area</th>
<th>Active Demand Response Available Summer 2015</th>
<th>Active Demand Response Available Summer 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>323</td>
<td>317</td>
</tr>
<tr>
<td>New England</td>
<td>638</td>
<td>700</td>
</tr>
<tr>
<td>New York</td>
<td>1,210</td>
<td>1,283</td>
</tr>
<tr>
<td>Ontario</td>
<td>859</td>
<td>806</td>
</tr>
<tr>
<td>Québec</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,030</strong></td>
<td><strong>3,106</strong></td>
</tr>
</tbody>
</table>

*Note: These values are based on the NPCC Coincident peak week.*

**Maritimes**

Interruptible loads are forecast on a weekly basis and range between 309 MW and 336 MW. The values can be found in Table API-2 and are available for use when corrective action is required within the Area.

**New England**

For the 2015 summer, ISO-NE has 638 MW of active demand resources that are expected to be available on peak. The active demand resources consist of real-time demand response (RTDR) of 446 MW and real-time emergency generation (RTEG) of 192 MW, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 - Action during a Capacity Deficiency (OP 4). These active demand resources can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of Real-Time Demand Resources, which is implemented in order to manage operating reserve requirements. Action 6, which is the dispatch of Real-Time Emergency Generation Resources, may be implemented to maintain 10-minute reserve. For the RTDR and RTEG resources audits conducted during the summer of 2014, performance

---

7 ISO New England Operating Procedure No. 4 can be found at [http://www.iso-ne.com/participate/rules-procedures/operating-procedures](http://www.iso-ne.com/participate/rules-procedures/operating-procedures)
equated to 104% of their Capacity Supply Obligation (CSO) across all load zones. The load zonal performance for each type ranged from 74% to 137% respectively.

In addition to active demand resources, there are 1,685 MW of passive demand resources (i.e. energy efficiency & conservation), which are treated as demand reducers in this report and accounted for in the load forecast of 26,710 MW. Without the effects of passive demand resources, the 2015 summer forecast would equate to 28,395 MW. These include installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. The amount of energy efficiency is based on capacity supply obligations in the Forward Capacity Market.

New York
The NYISO has three demand response programs to support system reliability. 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 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 NYISO currently projects 1,210 MW of total demand response available for the 2015 summer season.

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.

The United States Court of Appeals for the District of Columbia Circuit issued an order on May 23, 2014 striking down FERC Order No. 745 on the basis that (i) demand response is principally a retail activity and not subject to FERC jurisdiction; and (ii) that Order No. 745’s compensation scheme for demand response resources in energy markets was improper. On September 17, 2014, the Court of Appeals denied FERC’s request for rehearing en banc of Order No. 745. On January 15, 2015, the Solicitor General filed a Petition for a Writ of Certiorari with the Supreme Court. The Supreme Court has not yet acted on this petition. The Court of Appeals has stated that it would not issue its mandate implementing its decision until final resolution at the Supreme Court.

While Order No. 745 narrowly addressed compensation for demand response in energy markets, uncertainty remains as to whether the Court of Appeals’ opinion applies only to energy markets or to demand response in all wholesale electric markets.

The NYISO is obligated to administer its existing tariffs, including demand response, until it receives further direction by FERC. The NYISO is developing a backstop model in the stakeholder process, to replace the Special Case Resource program, in the event that its demand response programs are no longer subject to FERC jurisdiction. The goal of the plan is to minimize the market and reliability impact of the Court’s decision, and to allow the NYISO to quickly address guidance from FERC while maintaining the benefit of demand response in New York.

**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. The capacity of the demand response program consists of 678 MW of
dispatchable load, 519 MW of CBDR resources and 128 MW of Peaksaver resources. Although the total demand response capacity is 1,325 MW, the effective capacity is 859 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.

CBDR resources were transitioned from the Demand Response 3 program in March 2015, and are contracted for multi-year terms, expiring at the latest, in 2018. The total capacity for all of the resources is approximately 500 MW. A Demand Response Auction Auction is currently being developed by the IESO to maintain the existing DR Capacity and to replace the existing practice of multi-year contracting with a more cost-competitive mechanism, with the first auction expected to be held in December 2015. The IESO is also working to increase the role of demand response in Ontario to become more closely integrated with the day-to-day operations of the system. The IESO will be procuring up to 100 MW of price-responsive consumption capability from demand-side resources, to participate in pilot projects that will help identify opportunities to enhance DR participation in meeting system needs. The competitive Request for Proposal for the pilot was issued in April 2015. The DR Pilot program resources are expected to be in-service for summer 2016.

Québec
Demand Response programs are neither required nor available during the summer operating period.
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 Total Transfer Capabilities (TTC) and the TTC under Specified Conditions between the Balancing Authority Areas.

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; 288 MW for exports and imports. The transfers on the 115 kV is limited to 68 MW into Ontario, with no flow out allowed.

**Ontario – Minnesota Interconnection**

The Ontario – Minnesota interconnection consists of a single 115 kV circuit, with transfers 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 an export limit of 1,650 MW and an import limit of 1,600 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.

A new tap station, Mainesburg, is being constructed on the 345 kV Homer City-Watercure line between New York and PJM. Mainesburg is expected to be completed by June 2015. The new station will change the NY-PJM interface definition by replacing
the Homer City-Watercure (30) line with the Homer City-Mainesburg (47) line and adding a tie on the high side of the Mainesburg 345/115 transformer.

**Inter-Area Transmission Adequacy**

Appendix III provides a summary of the Normal Transfer Capabilities (NTC) on the interfaces between NPCC Reliability Coordinator areas and for some specific load zone areas. They also indicate the corresponding Feasible Transfer Capabilities (FTC) under peak conditions based on internal limitations or other factors and indicate the rationale behind reductions from the normal transfer capability.

The table below summarizes the feasible transfer capabilities between each region. Full details can be found in Appendix III.

**Table 6: Interconnection Transfer Capability Summary**

<table>
<thead>
<tr>
<th>Area</th>
<th>Transfer Capability under Forecasted Conditions (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Transfers from Maritimes to</strong></td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td>685</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>1,840</td>
</tr>
<tr>
<td>Québec</td>
<td>1,300</td>
</tr>
<tr>
<td><strong>Transfers from New York to</strong></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>1,930</td>
</tr>
<tr>
<td>Ontario</td>
<td>1,800</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>Québec</td>
<td>1,957</td>
</tr>
<tr>
<td><strong>Transfers from Québec to</strong></td>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
<td>700 + radial load</td>
</tr>
<tr>
<td>New England</td>
<td>1,660</td>
</tr>
<tr>
<td>New York</td>
<td>1,680</td>
</tr>
<tr>
<td>Ontario</td>
<td>2,640</td>
</tr>
</tbody>
</table>
**Area Transmission Adequacy Assessment**

Transmission system assessments are conducted in order to evaluate the resiliency and adequacy of the bulk power transmission system. Within each region, Areas evaluate the ongoing efforts and challenges of effectively managing the reliability of the bulk transmission system and identifying transmission system projects that would address local or system wide improvements. The CO-12 working group reviewed the forecasted conditions for the summer 2015 operating period under normal and peak demand configurations and have provided the following review as well as identified transmission the improvements listed in Table 7.

**Maritimes**

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Summer Operating Period. The Onslow substation transmission upgrade has increased the internal (Nova Scotia) transmission corridor transfer limits by removing the most severe contingency.

**New England**

The existing New England transmission system is projected to be sufficient for the 2015 summer assessment period. Transmission system upgrades continue to proceed in ISO-NE as they continually monitor transmission facility additions and coordinate outages in order to mitigate possible reliability risks and reduce economic impact that may be associated with changes in the transmission system.

New bulk power transmission facilities are anticipated to be placed in service in New England for the 2015 summer capacity period. Some of the more significant improvements include two new 345 kV transmission lines, one 345/115 kV transformer, two 40 MVar shunt reactors and the retirement of many Special Protection Schemes (SPS); all part of the Maine Power Reliability Project (MPRP). The first three are identified as the 3024 line from Albion Road to Coopers Mill, the 3025 line from Coopers Mill to Larrabee and the Coopers Mill 345/115 kV step down transformer. These elements are located in an area that joins the Northern and Central Loop regions of the MPRP project and will significantly reinforce power transfers into and out of the area.
Upon completion of the multi-year MPRP transmission project, it will have comprised of over four hundred and fifty miles of new or rebuilt 345 kV and 115 kV transmission lines, five new electric substations, six significant substation modifications or expansions, fifty remote end substation modifications or expansions, sixty line crossings and the retirement of six SPSs and one Automatic Closing Scheme (ACS). The following is a list of protection retirements and modifications scheduled for April, 2015:

- Retired - Maxcys-Bucksport SPS (NPCC # 178 – Type I) – This SPS action is to trip generation at Maine Independence Station and Bucksport Substation as well as
additional equipment at Maxcys and Albion Road Substations, for loss of the 388 line or 392 line. It is no longer needed with the addition of Coopers Mill, eliminating the single contingency loss of the only 345 kV path south of Orrington.

- Retired - Maine Yankee DCT SPS, (NPCC # 141 – Type I) – This SPS action is designed to trip all Maine Independence Station generation and trip generation and/or runback HVdc imports in New Brunswick on either loss of the 375 line (Maine Yankee – Surowiec) and the 392 line (Maine Yankee – Maxcys) or 375 line and 377 line (Maine Yankee – Surowiec). It is no longer needed with the addition of Coopers Mill, eliminating the single double circuit tower contingency loss of either the only two 345 kV paths south of Maine Yankee, or the single contingency loss of the only 345 kV path south of Orrington.

- Retired - Bucksport Reverse Power SPS (NPCC # 22 – Type III) – This SPS action is designed to be a redundant back up to the Orrington T1 SPS to avoid severe under voltage problems or voltage collapse around the Bangor and Bucksport area. It is no longer needed with the addition of Coopers Mill, adding a second 345 kV path south of Orrington and a third 115 kV path south of Orrington.

- Retired - Orrington T1 SPS (NPCC # 182 – Type III) – This SPS is designed to monitor the MW flow towards New Brunswick Power System Operator (NBPSO) on the Orrington (T1) 345/115 kV autotransformer when the Orrington-Maxcys (388) 345 kV line, the Orrington (T2) 345/115 kV autotransformer, and the Keene Road (T1) 345/115 kV autotransformer are out of service. It is no longer needed with the addition of Coopers Mill, adding a second 345 kV path south of Orrington and a third 115 kV path south of Orrington.

- Modified - Maine Input to Maritimes Islanding SPS (NPCC # 175 – Type I) - Maine inputs are no longer required with Coopers Mills, eliminated the single contingency loss of the only 345 kV path south of Orrington.

Within the state of Maine, transfer limits improvements and load serving capabilities have been achieved across multiple interfaces and have been provided below:

- New England to Maritimes: 600 MW (50 MW improvement) stability limit
- Maritimes to New England: 1,050 MW (50 MW improvement) voltage/stability limit
- Orrington South Interface: 1,325 MW (125 MW improvement) stability limit
- Orrington North Interface: Retired
Surowiec South Interface: 1,500 MW (350 MW improvement) stability limit

Maine – New Hampshire: 1,900 MW (200 MW improvement) stability limit

New Hampshire – Maine: Thermal limit improvements

The Interstate Reliability Project (IRP), a portion of the New England East-West Solution (NEEWS), is another major transmission project that plays a role in introducing further transmission improvements to the New England transmission system. Commissioning of the 3271 Line from Card to Lake Road will increase Connecticut import and export transfer capabilities and significantly improve local generation limitations during line out conditions. As the IRP project continues to progress, the local generation restrictions during line out conditions will be eliminated, energy transfer capability across the New England from East to West will be strengthened and improve transfers into and out of the Rhode Island load area.

**New York**

For the summer 2015 season New York does not anticipate any reliability issues for operating the bulk power system.

In March 2015 a new substation, Eastover Road, went into service tapping the 230 kV Rotterdam-Bear Swamp line between New York and New England. The station is located in New York near Albany, electrically connects to the local 115 kV system, and consequently changes the NY-NE interface definition to Eastover Road-Bear Swamp.

**Ontario**

For the summer 2015 operating period, Ontario’s transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmissions outages. With all transmission elements in service, the theoretical maximum capability for exports from Ontario is up to 5,960 MW, and 6,631 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 and external scheduling limitations, Ontario’s current expected coincident import capability is approximately 5,200 MW with all transmission elements in service.

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 summer 2015 season.
Québec

In the Québec Reliability Coordinator Area, most transmission line, transformer and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. As shown in Table AP-6 (Appendix I), Known Maintenance/Derates vary between 10,650 to 12,493 MW. During the Summer Operating Period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring Reliability Coordinator areas so as to leave maximum capability to summer peaking areas.
### 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>New York</td>
<td>Eastover Road Station</td>
<td>230 / 115</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Mainsburg Station (PJM)</td>
<td>345 / 115</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td>Ontario</td>
<td>Lambton TS: Station Upgrade</td>
<td>230 kV</td>
<td>Q2 - 2015</td>
</tr>
<tr>
<td></td>
<td>Build new Ashfield SS</td>
<td>500 kV</td>
<td>Q1 – 2015</td>
</tr>
<tr>
<td>Québec</td>
<td>New 300 Mvar Static Var Compensator at Bout-de-l’Ile substation (2/2)</td>
<td>735</td>
<td>Q3 - 2014</td>
</tr>
<tr>
<td></td>
<td>Two new 735/315 kV transformers at Bout-de-l’Ile substation</td>
<td>735 / 315</td>
<td>Q4 2014 and Q2 2015</td>
</tr>
<tr>
<td></td>
<td>162 miles transmission line from Arnaud substation to La Romaine-2 Power Plant</td>
<td>315</td>
<td>Q3 - 2014</td>
</tr>
<tr>
<td></td>
<td>Upgrade of Bergeronnes Series Capacitor Banks</td>
<td>735</td>
<td>Q2 - 2014</td>
</tr>
</tbody>
</table>
**Area Transmission Outage Assessment**

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

**Table 8: 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>NB/HQ</td>
<td>Eel River Cct 1</td>
<td>25-May-15</td>
<td>6-Jun-15</td>
<td>HQ to NB reduced by 175 MW</td>
</tr>
<tr>
<td>NB/HQ</td>
<td>Eel River Cct 2</td>
<td>1-Jun-15</td>
<td>8-Jun-15</td>
<td>HQ to NB reduced by 175 MW</td>
</tr>
</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>New England</td>
<td>Northport-Norwalk Harbor (NNC)</td>
<td>20-Apr-15</td>
<td>30-Apr-15</td>
<td>200 MW Both Directions</td>
</tr>
<tr>
<td>New England</td>
<td>Cross Sound Cable (CSC)</td>
<td>13-May-15</td>
<td>17-May-15</td>
<td>330 MW Both Directions</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>New England</td>
<td>Northport-Norwalk Harbor (NNC)</td>
<td>20-Apr-15</td>
<td>30-Apr-15</td>
<td>200 MW Both Directions</td>
</tr>
<tr>
<td>PJM</td>
<td>Neptune Cable</td>
<td>4-May-15</td>
<td>12-May-15</td>
<td>660 MW Import</td>
</tr>
<tr>
<td>HQ</td>
<td>Chateauguay-Massena 765 (7040)</td>
<td>4-May-15</td>
<td>22-May-15</td>
<td>1500 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1000 MW Export</td>
</tr>
<tr>
<td>HQ</td>
<td>Homer City-Watercure 345 (30)</td>
<td>4-May-15</td>
<td>28-May-15</td>
<td>250 MW Import</td>
</tr>
<tr>
<td>PJM</td>
<td>Hudson-Farragut 345 (B3402)</td>
<td>5-May-15</td>
<td>14-May-15</td>
<td>150 MW Import</td>
</tr>
<tr>
<td>HQ</td>
<td>Lowville-Boonville 115 (5-LB)</td>
<td>11-May-15</td>
<td>12-Jun-15</td>
<td>60 MW Import</td>
</tr>
<tr>
<td>New England</td>
<td>Cross Sound Cable (CSC)</td>
<td>13-May-15</td>
<td>17-May-15</td>
<td>330 MW Both Directions</td>
</tr>
<tr>
<td>PJM</td>
<td>Hudson-Farragut 345 (C3403)</td>
<td>16-May-15</td>
<td>25-May-15</td>
<td>150 MW Import</td>
</tr>
<tr>
<td>IESO</td>
<td>St. Lawrence-Moses 230 (L33P)</td>
<td>18-May-15</td>
<td>22-May-15</td>
<td>150 MW Both Directions</td>
</tr>
<tr>
<td>New England</td>
<td>Frost Bridge-Long Mountain 345 (352)</td>
<td>22-May-15</td>
<td>31-May-15</td>
<td>300 MW Import</td>
</tr>
<tr>
<td>IESO</td>
<td>St. Lawrence-Moses 230 (L34P)</td>
<td>26-May-15</td>
<td>29-May-15</td>
<td>150 MW Both Directions</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>800 MW Export</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>HQ</td>
<td>D4Z (Dymond x Rapide Des Isle)</td>
<td>25-May-15</td>
<td>12-Jun-15</td>
<td>0 MW Import</td>
</tr>
<tr>
<td>HQ</td>
<td>H4Z (Holden x Rapide Des Isle)</td>
<td>4-May-15</td>
<td>6-May-15</td>
<td>0 MW Export</td>
</tr>
<tr>
<td>NY</td>
<td>L33P</td>
<td>18-May-15</td>
<td>22-May-15</td>
<td>150 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>150 MW Import</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>New Brunswick</td>
<td>Madawaska</td>
<td>2-May-15</td>
<td>24-May-15</td>
<td>700 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>685 MW Import</td>
</tr>
<tr>
<td>New York</td>
<td>Massena (L7040)</td>
<td>4-May-15</td>
<td>22-May-15</td>
<td>1800 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1000 MW Import</td>
</tr>
<tr>
<td>New York</td>
<td>Massena (GC2)</td>
<td>22-May-15</td>
<td>3-Jun-15</td>
<td>300 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>500 MW Import</td>
</tr>
</tbody>
</table>
6. **Operational Readiness for 2015**

**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 is a winter peaking area and because of this the possibility of light system loads along with high wind generator outputs could occur. If this scenario were to happen, procedures are in place to mitigate the event by taking corrective actions (up to and including the curtailment of wind resources). Any internal operating condition within the Maritimes will be handled with Short Term Operating Procedures (STOP).

*Wind Integration*

The 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 - *Standards for Voltage Reduction and Load Shedding Capability (OP-13)*. With the validated results, ISO New England does not anticipate any voltage concerns for the summer capacity period as transmission reactive resources and generator reactive capabilities will be monitored and controlled for safe and reliable operation on the bulk power system.

*Integration of Solar Energy*

With the integration of solar energy, New England experiences unique challenges with interconnection and observability of the solar photovoltaic resources (PV). Because

---

8 Operating Procedure No. 13 is located on the ISO’s web site at: http://www.iso-ne.com/rules_proceeds/operating/isone/op13/index.html
many of these resources are located behind the meter and are small in comparison to conventional generators throughout the system, the power output is not dispatchable and appears as a demand reducer to system operators. This creates unique challenges in the near-term system load forecasting function of ISO-NE as approximately 900 MW of solar power has been installed by retail customers and local utilities. This capacity value is expected to increase over the next ten years and the integration of solar and other renewable resources will continue to be of key importance.

**Zonal Load Forecasting**

New England continues to use a 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. An example would be when the Boston zone is forecasted to be sixty five degrees while the Hartford area is forecasting ninety degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The eight zones are then summed for a total New England load. As part of an ongoing effort to further improve the accuracy of the ISO-NE load forecast as well as the reliable operation of the New England grid, System Operations initiated a proto-type Reliability Region hourly load forecast in December 2013. This set of load forecasts at the Reliability Region level has two benefits.

1. The sum of the Reliability Region load forecasts complements the multiple load forecast engines that forecast the New England load.

2. The individual Reliability Region load forecasts provide a breakdown of the distribution of the load within New England. These regional forecasts add value to ISO operations and outage coordination processes by providing a weather based load forecast as opposed to distribution of the ISO-NE load forecast using historical (Static) distribution factors.

ISO-NE plans to upgrade the proto-type process into the production environment by Q1 2016.

**Natural Gas Supply**

While natural gas has become the predominant fuel source in New England, the ISO continues to monitor impacting factors to the natural gas fuel deliverability throughout the winter and summer reliability assessment periods. For the 2015 summer capacity period, the ISO expects some natural gas pipeline maintenance to occur for select areas but does not forecast deliverability issues that would affect the installed capacity. The ISO does expect some impact in late September as Spectra Energy will be performing
maintenance and expansion of their pipeline through the Algonquin Incremental Market (AIM) project. In review of the proposed schedule, it is determined the work performed through much of the summer capacity period should have no impact to our natural gas fired generating fleet. More significant restrictions are expected to occur in late September which will be taken into consideration with the transmission and generation outage scheduling process. ISO-NE continues to share confidential information concerning natural gas-fueled generation located in New England with the operating personnel of interstate natural gas pipeline companies, provided that the information is operationally necessary and that it will be shared only with the pipeline company directly serving that generator. This information exchange includes maintenance schedules to promote outage coordination between the industries, output schedules for individual generators and discussion of any real-time information concerning specific resources for the purpose of maintaining reliability.

ISO-NE and the interstate natural gas pipeline operators continue to improve the forecast of their combined systems, discuss specific system conditions, and may be able to take actions, under their existing authorities, to avoid reliability problems. When sharing this information with the interstate natural gas pipeline operators, the pipeline operators may be able to provide information on gas availability that will allow ISO-NE to better anticipate and address potential reliability problems in the event that there is insufficient fuel for all gas-fired generators to meet their schedules. Along with near-term weather data, load forecasts and planned outage conditions, this information is also used to develop short-term and long-term operating plans.

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

1. ISO-NE’s Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP 4) is a procedure that establishes criteria and guidelines for actions during capacity deficiencies resulting from generator and transmission contingencies and prescribe actions to manage Operating Reserve Requirements.\(^9\)

2. ISO-NE’s Operating Procedure No. 7 – *Action in an Emergency* (OP 7) is a procedure that establishes criteria to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, capacity or

\(^9\) 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
energy deficiency, unacceptable voltage levels, or any other emergency that ISO-NE deems appropriate in an isolated or widespread area of New England.\(^{10}\)

3. ISO-NE’s Operating Procedure No. 21 - Action During an Energy Emergency (OP 21) is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel supply deficiencies that can occur anytime during the year\(^{11}\). 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 (NYSRC) Installed Reserve Margin (IRM) of 17% for the 2015 summer season.

The weather-normalized 2014 peak was 33,291 MW, 375 MW (1.11%) lower than the forecast of 33,666 MW prepared in December 2013. The current 2015 peak forecast is 33,567 MW and was updated in December 2014. It is lower than the December 2013 forecast by 99 MW (0.29%). This is attributed to a decrease in industrial load upstate; annual growth rates in other areas of the state were the same or nearly the same as last year. There are two higher-than-expected scenarios forecast. One is a forecast without the impacts of energy efficiency programs or behind-the-meter solar photovoltaic generation. The high growth forecast for the summer of 2015 is 33,890 MW. The second is a forecast based on extreme weather conditions, set to the 90\(^{th}\) percentile of typical peak-producing weather conditions. The extreme weather forecast for 2015 is 35,862 MW.

No unique operational problems were observed from NYISO capability assessment studies. Since the summer of 2014, there have been net nameplate additions of 775 MW. The Danskammer plant, located in the Hudson Valley, was repowered in Fall 2014. It was converted from coal to natural gas and oil. Other net nameplate additions are 227 MW of dual fuel (oil/nat. gas) and 16 MW of wind generation.

\(^{10}\) Operating Procedure No. 7 is located on the ISO’s web site at: [http://www.iso-ne.com/rules_proce...]{http://www.iso-ne.com/rules_proceeds/operating/isone/op7/op7_rto_final.pdf}

\(^{11}\) Operating Procedure No. 21 is located on the ISO’s web site at: [http://www.iso-ne.com/rules_proce...]{http://www.iso-ne.com/rules_proceeds/operating/isone/op21/op21_rto_final.pdf}
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 identifies to neighboring control areas the capacity-backed transactions that are expected to be both imported into and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2015 summer season, New York expects to have 2,522 MW of net import capacity available.

The NYISO anticipates sufficient resources, including demand response, 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) designs 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 DR 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.

Voltage Control

The NYISO does not foresee any voltage issues for the upcoming summer season. Generators are compensated for reactive capability and are required to maintain Automatic Voltage Regulators (AVRs) in service at all times for said compensation. Generators must adjust their VAr output when called upon to provide voltage support. The NYCA also has two Static VAR Compensators (SVCs) at Fraser and Leeds as well as a Convertible Static Compensator (STATCOM) at Marcy which can provide either dynamic or static VAr support as needed. Furthermore, switched shunt capacitors and reactors are installed at key locations throughout the bulk power system to be utilized for voltage control.

Environmental Impacts

High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals; this could occur during long duration hot weather events or following the loss of significant generation or transmission assets in NYC. In 2001, the New York State Department of Environmental Conservation (DEC) extended a prior agreement with the New York Power Pool to address the potential violation of NOx and opacity regulations if the NYISO were required to keep these peaking units operating to avoid the loss of load. Under this agreement (DEC, Declaratory Order # 19-12) if the NYISO were to issue an instruction to a Generator to go to maximum capability, in order to
avoid loss of load, any violations of NOx RACT emission limits or opacity requirements imposed under DEC regulations would be subject to the affirmative defense for emergency conditions. This determination is limited to circumstances where the maximum capability requested by the NYISO would involve the generation of the highest level of electrical power achievable by the subject Generators with the continued use of properly maintained and operating pollution control equipment required by all applicable air pollution control requirements.

**Ontario**

*Base Load*

During the summer period, Ontario expects to have sufficient electricity to meet its projected needs; however planned nuclear outages occurring at the start of the summer assessment period will slightly reduce net margins. Occurrences of surplus base load generation (SBG) are likely to occur during the assessment period, with a decline in SBG at the start of the period, coinciding with the planned nuclear outages. With the addition of significant wind supplies, there is potential for increased nuclear maneuvering, dispatch of grid-connected renewable resources and intertie scheduling. It is expected that SBG will be managed effectively during this operating period via these normal market mechanisms. Embedded solar generation will continue to reduce demand on the transmission system, in particular during summer peaks. The summer peaks will also be subject to lower demands due to the Industrial Conservation Initiative (ICI).

*Voltage Control*

Although Ontario does not foresee any voltage issues this summer season, managing grid voltages will be challenging during the nuclear outages occurring at the start of the summer assessment period, especially during off-peak periods. Studies to determine the best methods of voltage control have been completed, with plans in place to manage grid security. The IESO has also been actively working with transmitters, generators, natural gas pipelines and interconnected neighbours to ensure reliable operation during this period.

High voltages in southern Ontario continue to occur, especially during periods of light load. The removal of at least one 500 kV circuit may be required to help in reducing voltages. Conditions also become more acute during periods when shunt reactors are unavailable. Procedures are in place for day-to-day operations, and planning work has been initiated for the installation of new voltage control devices.
Operating Procedures

Ontario expects to have sufficient electricity to meet its forecasted demand, and is continuing to work on enhancing communication protocols with gas pipeline and distribution system operators. In preparation for the summer season, IESO will meet with gas pipeline operators in April to discuss gas supply and planned maintenance on the gas and electric systems.

Québec

Equipment Maintenance

Most transmission line, transformer and generating unit maintenance is done during the summer period. The maintenance outages are being planned so that all exports can be maintained.

Voltage Control

Québec is a winter peaking area. During summer periods, reactive capability of generators is not a problem. TransÉnergie does not expect to encounter any kind of low voltage problem during the summer. On the contrary, controlling over voltages on the 735 kV network during off-peak hours is the concern. This is accomplished mainly with the use of shunt reactors. Typically, about 15,000 MVar of 735 kV shunt reactors may be connected at any given time during the summer, with seven to ten 735 kV lines out of service for maintenance. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

Thermal limits

On a few occasions during the last summers, several 735 kV lines in the southern part of the system became heavily loaded, due to the hot temperatures in southern Québec. Although this is a new issue at Hydro-Québec, the situation is expected to happen again because summers are getting warmer, the air conditioning load is increasing year after year and transfers to summer peaking systems are increasing. Studies have been performed, thermal limits have been optimized and mitigating measures have been implemented to ensure that no line becomes overloaded following a contingency in hot temperature periods.

Disturbance event that occurred on July 3, 2013

Following the disturbance event that occurred on July 3, 2013 on the Hydro-Québec TransÉnergie (HQT) transmission system, HQT provided information related to this event to the NPCC.
In December 2013, NPCC created a working group to further analyze the operations and design of the transmission system. The event has been presented for discussions to various NPCC technical and operational Task Forces. Following the review of the findings and recommendations, system limits are now adjusted according to the intensity of forest fires when they occur and operating procedures have been updated accordingly.

**Summer 2015 Solar Terrestrial Dispatch Forecast of Geomagnetically Induced Current**

*Solar Activity Forecast Discussion*

The occurrence frequency of solar disturbances continues to be below-normal for this phase of the solar cycle and this is expected to persist through the coming year. However, the frequency of faster-moving coronal mass ejections will increase during this phase of the cycle and will peak about 2 years from now. Stable structures on the Sun allow us to predict well in advance periods of increased risk for minor GIC activity. At the time of this writing, these structures suggest that activity will become less stable and more conducive for minor GIC activity during the latter-half of each month during the coming summer assessment period. The more stable and quieter periods of GIC occurring during the early half of each month. Although stable structures won’t impact as much during the early half of each month, the early half of the month will be dominated by the most active solar longitudes (where sunspot formation is the most active). Since high-velocity coronal mass ejections can occur from these areas (rather than from stable solar structures), the risk for solar disturbances capable of producing higher geomagnetic K-indices and stronger GIC levels will be during the early half of each month. The events associated with sunspot groups cannot be reliably predicted more than 72 hours in advance, so it will be important for operators to keep an eye on current forecasts at all times of the month.

This means that the entire month is now susceptible to periods of GIC activity and reliance on shorter-term 72-hour forecasts will increase.

It is expected that there will be an overall gradual increase in the number of GIC-capable events during the next year, a small few of which could be fairly significant. The majority will be small events producing nothing more than minor GIC activity, but their frequency of occurrence should gradually increase.

In summary, the period near the 13th to the 30th of each month during the summer assessment period will be more susceptible to several periods of minor GIC activity. By the end of summer, this “zone” may shift to the earlier part of the month (from about the 8th to the 25th of each month). During the 1st to the 13th of each month, there will be a slight but notably increased risk of stronger GIC events from active sunspot groups.
producing solar flares and attendant higher-velocity coronal mass ejections. We expect GIC activity in general to slowly increase in frequency during the coming year.
7. Post-Seasonal Assessment and Historical Review

Summer 2014 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator area’s summer 2014 operational experiences.

The NPCC coincident peak 96,068 MW, occurred on July 1, 2014 at HE17 EDT.

Maritimes

The Maritimes peak demand during the NPCC coincident peak was 2,806 MW. Maritimes actual peak was 3,721 MW on April 30, 2014 at HE7 EDT.

All major transmission lines were in service. The Eel River HVDC between New Brunswick and Quebec had been out of service for refurbishment, this outage did not cause any system reliability issues.

New England

The forecasted normal peak demand for summer 2014 was 26,658 MW.

The actual peak demand of 24,443 MW occurred July 2nd, HE15 EDT. During the NPCC coincident peak week, the actual peak demand of 23,099 MW.

On Sunday, September 28, 2014, ISO New England implemented Master/Local Control Center Procedure #2 (M/LCC 2), Abnormal Conditions Alert and Operating Procedure #4 (OP#4), Action During a Capacity Deficiency, to manage a deficiency in Operating Reserve. The Morning Report projected an operating reserve surplus of 872 MW, based on the forecast load of 16,380 MW. Actual temperature in Hartford was 3 degrees higher than forecasted, and in Boston the actual temperature was 9 degrees higher than forecasted. The expected net import delivery for the peak hour was 1,874MW and the actual net imports delivered were 2,076 MW.

In addition to other reductions of capacity on various units, at approximately 18:10, a large unit rated for approximately 600 MW, was forced off line due to a mechanical problem. All available capacity units that could start in less than 2 hours, 238 MW, were ordered on-line. At 18:50, M/LCC 2 was declared due to a capacity deficiency for all of New England. At 19:00, OP4 Action 1 was entered due to a deficiency of 30 minute operating reserve. Action 1 of OP#4 was cancelled at 20:30 and M/LCC 2 was cancelled at 22:00.
**New York**

The actual peak demand of 29,782 MW occurred September 2nd, HE16 EDT. During the NPCC coincident peak week, the actual peak demand was 29,330 MW.

There were no fuel supply, transmission or reactive capability issues.

**Ontario**

The actual peak demand was 21,363 MW on August 26, 2014 HE17 EST. During the NPCC coincident peak week, the actual peak demand was 20,332 MW.

No significant events impacting the reliability of the transmission system occurred during the summer 2014 operating period.

**Québec**

The Québec actual internal peak demand for summer 2014 occurred on August 26 and was 21,165 MW. The Québec actual internal demand coincident to the NPCC peak was 20,500 MW. The all-time summer peak demand record is 22,092 MW in July 2010. Transfers to other areas during the NPCC coincident peak were approximately 6,000 MW. No resource adequacy event occurred during the 2014 Summer Operating Period.
Historical Summer Demand Review (Pre-2015)

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

Table 6: Ten Year Historical Summer 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 Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>3,821</td>
<td>26,885</td>
<td>32,075</td>
<td>26,160</td>
<td></td>
<td>111,306</td>
</tr>
<tr>
<td>2006</td>
<td>3,385</td>
<td><strong>28,127</strong></td>
<td>33,939</td>
<td><strong>27,005</strong></td>
<td>21,361</td>
<td><strong>113,817</strong></td>
</tr>
<tr>
<td>2007</td>
<td><strong>3,886</strong></td>
<td>26,145</td>
<td>32,169</td>
<td>25,737</td>
<td>21,411</td>
<td>109,348</td>
</tr>
<tr>
<td>2008</td>
<td>3,675</td>
<td>26,111</td>
<td>32,432</td>
<td>24,195</td>
<td>21,488</td>
<td>107,901</td>
</tr>
<tr>
<td>2009</td>
<td>3,566</td>
<td>25,100</td>
<td>30,843</td>
<td>24,380</td>
<td>21,141</td>
<td>105,030</td>
</tr>
<tr>
<td>2010</td>
<td>3,497</td>
<td>27,102</td>
<td>33,452</td>
<td>25,075</td>
<td>22,092</td>
<td>111,218</td>
</tr>
<tr>
<td>2011</td>
<td>3,725</td>
<td>27,707</td>
<td>33,865</td>
<td>23,342</td>
<td>21,356</td>
<td>109,995</td>
</tr>
<tr>
<td>2012</td>
<td>3,403</td>
<td>25,880</td>
<td>32,439</td>
<td>24,636</td>
<td>21,938</td>
<td>108,296</td>
</tr>
<tr>
<td>2013</td>
<td>3,299</td>
<td>27,379</td>
<td><strong>33,956</strong></td>
<td>24,927</td>
<td>21,702</td>
<td>111,263</td>
</tr>
<tr>
<td>2014</td>
<td>3,721</td>
<td>24,443</td>
<td>29,782</td>
<td>21,363</td>
<td>21,165</td>
<td>100,474</td>
</tr>
<tr>
<td>2015</td>
<td>3,748</td>
<td>26,710</td>
<td>33,567</td>
<td>22,991</td>
<td>21,090</td>
<td>108,106</td>
</tr>
</tbody>
</table>
8. **2015 Reliability Assessments of Adjacent Regions**

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

[https://www.rfirst.org/reliability/Pages/ReliabilityReports.aspx](https://www.rfirst.org/reliability/Pages/ReliabilityReports.aspx)

For reviews of the NERC reliability regions and some of the large Balancing Authority areas go to:

[http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx](http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx)
9. **CP-8 2015 Summer Multi-Area Probabilistic Reliability Assessment Executive Summary**

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

Table AP-1 - NPCC Summary

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>26-Apr-15</td>
<td>159.162</td>
<td>1.626</td>
<td>160.788</td>
<td>79.291</td>
<td>2.725</td>
<td>36.969</td>
<td>8.238</td>
<td>8.866</td>
<td>45.855</td>
<td>30.129</td>
<td>38.0%</td>
<td>28.577</td>
</tr>
<tr>
<td>10-May-15</td>
<td>159.401</td>
<td>1.484</td>
<td>160.885</td>
<td>82.095</td>
<td>3.067</td>
<td>34.681</td>
<td>8.238</td>
<td>9.033</td>
<td>43.714</td>
<td>29.905</td>
<td>36.4%</td>
<td>26.052</td>
</tr>
<tr>
<td>17-May-15</td>
<td>159.401</td>
<td>1.678</td>
<td>161.079</td>
<td>83.678</td>
<td>3.055</td>
<td>30.780</td>
<td>8.238</td>
<td>9.378</td>
<td>40.158</td>
<td>32.060</td>
<td>38.3%</td>
<td>27.067</td>
</tr>
<tr>
<td>31-May-15</td>
<td>156.812</td>
<td>1.690</td>
<td>156.502</td>
<td>103.904</td>
<td>3.031</td>
<td>25.031</td>
<td>8.238</td>
<td>9.029</td>
<td>34.060</td>
<td>15.331</td>
<td>14.8%</td>
<td>10.951</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>157.441</td>
<td>1.680</td>
<td>159.121</td>
<td>94.519</td>
<td>3.040</td>
<td>30.113</td>
<td>8.238</td>
<td>7.739</td>
<td>37.852</td>
<td>21.552</td>
<td>22.8%</td>
<td>18.247</td>
</tr>
</tbody>
</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 C
4) Revised Net Margin = Net Margin - Bottled resources
5) Revised Extreme Net Margin = Net Margin - Bottled resources
### Table AP-2 – Maritimes

<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>
</tr>
</thead>
<tbody>
<tr>
<td>26-Apr-15</td>
<td>7695</td>
<td>0</td>
<td>7695</td>
<td>3748</td>
<td>312</td>
<td>2048</td>
<td>734</td>
<td>276</td>
<td>1201</td>
<td>32.0%</td>
</tr>
<tr>
<td>3-May-15</td>
<td>7722</td>
<td>0</td>
<td>7722</td>
<td>3661</td>
<td>319</td>
<td>2131</td>
<td>734</td>
<td>278</td>
<td>1237</td>
<td>33.8%</td>
</tr>
<tr>
<td>10-May-15</td>
<td>7722</td>
<td>0</td>
<td>7722</td>
<td>3607</td>
<td>323</td>
<td>1978</td>
<td>734</td>
<td>278</td>
<td>1448</td>
<td>40.1%</td>
</tr>
<tr>
<td>17-May-15</td>
<td>7722</td>
<td>0</td>
<td>7722</td>
<td>3552</td>
<td>311</td>
<td>1605</td>
<td>734</td>
<td>278</td>
<td>1864</td>
<td>52.5%</td>
</tr>
<tr>
<td>24-May-15</td>
<td>7722</td>
<td>0</td>
<td>7722</td>
<td>3401</td>
<td>311</td>
<td>1714</td>
<td>734</td>
<td>278</td>
<td>1906</td>
<td>56.0%</td>
</tr>
<tr>
<td>31-May-15</td>
<td>7722</td>
<td>0</td>
<td>7722</td>
<td>3286</td>
<td>312</td>
<td>1784</td>
<td>734</td>
<td>278</td>
<td>1952</td>
<td>59.4%</td>
</tr>
<tr>
<td>7-Jun-15</td>
<td>7723</td>
<td>0</td>
<td>7723</td>
<td>3207</td>
<td>311</td>
<td>1906</td>
<td>734</td>
<td>278</td>
<td>1909</td>
<td>59.5%</td>
</tr>
<tr>
<td>14-Jun-15</td>
<td>7723</td>
<td>0</td>
<td>7723</td>
<td>3183</td>
<td>320</td>
<td>1869</td>
<td>734</td>
<td>278</td>
<td>1979</td>
<td>62.2%</td>
</tr>
<tr>
<td>21-Jun-15</td>
<td>7723</td>
<td>0</td>
<td>7723</td>
<td>3197</td>
<td>320</td>
<td>1644</td>
<td>734</td>
<td>278</td>
<td>2190</td>
<td>68.5%</td>
</tr>
<tr>
<td>28-Jun-15</td>
<td>7723</td>
<td>0</td>
<td>7723</td>
<td>3218</td>
<td>317</td>
<td>1616</td>
<td>734</td>
<td>278</td>
<td>2194</td>
<td>68.2%</td>
</tr>
<tr>
<td>5-Jul-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3213</td>
<td>323</td>
<td>1674</td>
<td>734</td>
<td>278</td>
<td>2150</td>
<td>66.9%</td>
</tr>
<tr>
<td>12-Jul-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3218</td>
<td>315</td>
<td>1671</td>
<td>734</td>
<td>278</td>
<td>2140</td>
<td>66.5%</td>
</tr>
<tr>
<td>19-Jul-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3226</td>
<td>322</td>
<td>1667</td>
<td>734</td>
<td>278</td>
<td>2143</td>
<td>66.4%</td>
</tr>
<tr>
<td>26-Jul-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3226</td>
<td>311</td>
<td>1650</td>
<td>734</td>
<td>278</td>
<td>2149</td>
<td>66.6%</td>
</tr>
<tr>
<td>2-Aug-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3244</td>
<td>309</td>
<td>1615</td>
<td>734</td>
<td>278</td>
<td>2164</td>
<td>66.7%</td>
</tr>
<tr>
<td>9-Aug-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3274</td>
<td>315</td>
<td>1720</td>
<td>734</td>
<td>278</td>
<td>2035</td>
<td>62.2%</td>
</tr>
<tr>
<td>16-Aug-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3276</td>
<td>321</td>
<td>2044</td>
<td>734</td>
<td>278</td>
<td>1715</td>
<td>52.4%</td>
</tr>
<tr>
<td>23-Aug-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3264</td>
<td>325</td>
<td>2065</td>
<td>734</td>
<td>278</td>
<td>1710</td>
<td>52.4%</td>
</tr>
<tr>
<td>30-Aug-15</td>
<td>7726</td>
<td>0</td>
<td>7726</td>
<td>3294</td>
<td>331</td>
<td>1809</td>
<td>734</td>
<td>278</td>
<td>1942</td>
<td>59.0%</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>7741</td>
<td>0</td>
<td>7741</td>
<td>3237</td>
<td>321</td>
<td>1788</td>
<td>734</td>
<td>278</td>
<td>2025</td>
<td>62.6%</td>
</tr>
<tr>
<td>13-Sep-15</td>
<td>7741</td>
<td>0</td>
<td>7741</td>
<td>3234</td>
<td>336</td>
<td>2115</td>
<td>734</td>
<td>278</td>
<td>1716</td>
<td>53.1%</td>
</tr>
</tbody>
</table>

**Notes**
### Table AP-3 – New England

<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>
</tr>
</thead>
<tbody>
<tr>
<td>26-Apr-15</td>
<td>32.828</td>
<td>812</td>
<td>33.640</td>
<td>16.270</td>
<td>460</td>
<td>4.606</td>
<td>2.375</td>
<td>3.400</td>
<td>7.449</td>
<td>45.8%</td>
</tr>
<tr>
<td>9-May-15</td>
<td>32.915</td>
<td>812</td>
<td>33.727</td>
<td>17.500</td>
<td>663</td>
<td>6.645</td>
<td>2.375</td>
<td>3.400</td>
<td>4.470</td>
<td>26.5%</td>
</tr>
<tr>
<td>10-May-15</td>
<td>32.915</td>
<td>618</td>
<td>33.533</td>
<td>19.945</td>
<td>663</td>
<td>4.035</td>
<td>2.375</td>
<td>3.400</td>
<td>4.441</td>
<td>21.2%</td>
</tr>
<tr>
<td>17-May-15</td>
<td>32.915</td>
<td>812</td>
<td>33.727</td>
<td>20.942</td>
<td>663</td>
<td>2.762</td>
<td>2.375</td>
<td>3.400</td>
<td>4.911</td>
<td>26.3%</td>
</tr>
<tr>
<td>24-May-15</td>
<td>32.915</td>
<td>812</td>
<td>33.727</td>
<td>21.868</td>
<td>663</td>
<td>1.892</td>
<td>2.375</td>
<td>3.400</td>
<td>4.855</td>
<td>22.2%</td>
</tr>
<tr>
<td>31-May-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.800</td>
<td>316</td>
<td>1.2%</td>
</tr>
<tr>
<td>7-Jun-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.800</td>
<td>316</td>
<td>1.2%</td>
</tr>
<tr>
<td>14-Jun-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.800</td>
<td>316</td>
<td>1.2%</td>
</tr>
<tr>
<td>21-Jun-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.800</td>
<td>316</td>
<td>1.2%</td>
</tr>
<tr>
<td>28-Jun-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.800</td>
<td>316</td>
<td>1.2%</td>
</tr>
<tr>
<td>5-Jul-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>12-Jul-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>19-Jul-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>26-Jul-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>2-Aug-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>9-Aug-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>16-Aug-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>23-Aug-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.563</td>
<td>26.710</td>
<td>638</td>
<td>0</td>
<td>2.375</td>
<td>2.100</td>
<td>1.016</td>
<td>3.8%</td>
</tr>
<tr>
<td>30-Aug-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.569</td>
<td>26.710</td>
<td>638</td>
<td>552</td>
<td>2.375</td>
<td>2.100</td>
<td>470</td>
<td>1.8%</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.569</td>
<td>23.016</td>
<td>638</td>
<td>2,174</td>
<td>2.375</td>
<td>2.100</td>
<td>2,542</td>
<td>11.0%</td>
</tr>
<tr>
<td>13-Sep-15</td>
<td>30.326</td>
<td>1.237</td>
<td>31.569</td>
<td>23.016</td>
<td>638</td>
<td>2,174</td>
<td>2.375</td>
<td>2.100</td>
<td>2,542</td>
<td>11.0%</td>
</tr>
</tbody>
</table>

**Notes**

1. Installed Capacity based on Seasonal Claimed Capabilities and ISO-NE Forward Capacity Market (FCM) resource obligations for the 2015-2016 capacity commitment.
2. Net Interchange includes peak purchases/sales from Maritimes, Quebec and New York.
3. Load Forecast assumes Peak Load Exposure of 26,710 MW, which can be found in the 2015 CELT Report and does include 1,685 MW credit of Passive Demand Response.
4. On peak, Interruptible Loads consist of both Active Demand Response (446 MW) and fast-start FCM Demand Resource (192MW) obligations.
5. Includes known scheduled maintenance as of March 30, 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 summer 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.
## 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>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
</tr>
</thead>
<tbody>
<tr>
<td>26-Apr-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>19,929</td>
<td>1,210</td>
<td>7,068</td>
<td>1,965</td>
<td>2,776</td>
<td>10,694</td>
<td>53.7%</td>
</tr>
<tr>
<td>3-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>19,661</td>
<td>1,210</td>
<td>6,241</td>
<td>1,965</td>
<td>2,814</td>
<td>11,751</td>
<td>59.8%</td>
</tr>
<tr>
<td>10-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>19,680</td>
<td>1,210</td>
<td>5,568</td>
<td>1,965</td>
<td>2,846</td>
<td>12,373</td>
<td>62.9%</td>
</tr>
<tr>
<td>17-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>20,744</td>
<td>1,210</td>
<td>5,238</td>
<td>1,965</td>
<td>2,861</td>
<td>11,624</td>
<td>56.0%</td>
</tr>
<tr>
<td>24-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>23,215</td>
<td>1,210</td>
<td>4,189</td>
<td>1,965</td>
<td>2,509</td>
<td>10,154</td>
<td>43.7%</td>
</tr>
<tr>
<td>31-May-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>2,352</td>
<td>1,965</td>
<td>2,995</td>
<td>1,553</td>
<td>4.6%</td>
</tr>
<tr>
<td>7-Jun-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>2,085</td>
<td>1,965</td>
<td>3,007</td>
<td>1,008</td>
<td>5.4%</td>
</tr>
<tr>
<td>14-Jun-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,924</td>
<td>1,965</td>
<td>3,014</td>
<td>1,962</td>
<td>5.8%</td>
</tr>
<tr>
<td>21-Jun-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,909</td>
<td>1,965</td>
<td>3,015</td>
<td>1,976</td>
<td>5.9%</td>
</tr>
<tr>
<td>28-Jun-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,961</td>
<td>1,965</td>
<td>3,015</td>
<td>1,984</td>
<td>5.9%</td>
</tr>
<tr>
<td>5-Jul-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,899</td>
<td>1,965</td>
<td>3,016</td>
<td>1,985</td>
<td>5.9%</td>
</tr>
<tr>
<td>12-Jul-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,866</td>
<td>1,965</td>
<td>3,017</td>
<td>2,017</td>
<td>6.0%</td>
</tr>
<tr>
<td>19-Jul-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,866</td>
<td>1,965</td>
<td>3,017</td>
<td>2,017</td>
<td>6.0%</td>
</tr>
<tr>
<td>26-Jul-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,866</td>
<td>1,965</td>
<td>3,017</td>
<td>2,026</td>
<td>6.0%</td>
</tr>
<tr>
<td>2-Aug-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,878</td>
<td>1,965</td>
<td>3,017</td>
<td>2,015</td>
<td>6.0%</td>
</tr>
<tr>
<td>9-Aug-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,890</td>
<td>1,965</td>
<td>3,016</td>
<td>2,004</td>
<td>6.0%</td>
</tr>
<tr>
<td>16-Aug-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,879</td>
<td>1,965</td>
<td>3,017</td>
<td>2,014</td>
<td>6.0%</td>
</tr>
<tr>
<td>23-Aug-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,875</td>
<td>1,965</td>
<td>3,017</td>
<td>2,018</td>
<td>6.0%</td>
</tr>
<tr>
<td>30-Aug-15</td>
<td>38,700</td>
<td>2,522</td>
<td>41,222</td>
<td>33,567</td>
<td>1,210</td>
<td>1,883</td>
<td>1,965</td>
<td>3,017</td>
<td>2,010</td>
<td>6.0%</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>38,710</td>
<td>2,522</td>
<td>41,232</td>
<td>25,127</td>
<td>1,210</td>
<td>1,868</td>
<td>1,965</td>
<td>3,017</td>
<td>10,465</td>
<td>41.6%</td>
</tr>
<tr>
<td>13-Sep-15</td>
<td>38,710</td>
<td>2,522</td>
<td>41,232</td>
<td>24,580</td>
<td>1,210</td>
<td>2,461</td>
<td>1,965</td>
<td>2,990</td>
<td>10,446</td>
<td>42.5%</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 transaction data is confidential by market rules.

3. 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.
<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./Bottled Cap. 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>26-Apr-15</td>
<td>35.126</td>
<td>0</td>
<td>35.126</td>
<td>17.445</td>
<td>743</td>
<td>10.754</td>
<td>1.664</td>
<td>1.234</td>
<td>4.772</td>
<td>27.4%</td>
</tr>
<tr>
<td>3-May-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>17.600</td>
<td>871</td>
<td>10.926</td>
<td>1.664</td>
<td>1.313</td>
<td>4.619</td>
<td>26.2%</td>
</tr>
<tr>
<td>10-May-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>18.539</td>
<td>871</td>
<td>10.707</td>
<td>1.664</td>
<td>1.309</td>
<td>3.903</td>
<td>21.1%</td>
</tr>
<tr>
<td>17-May-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>18.884</td>
<td>871</td>
<td>8.738</td>
<td>1.664</td>
<td>1.639</td>
<td>5.197</td>
<td>27.5%</td>
</tr>
<tr>
<td>24-May-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>19.370</td>
<td>871</td>
<td>8.660</td>
<td>1.664</td>
<td>1.794</td>
<td>4.634</td>
<td>23.9%</td>
</tr>
<tr>
<td>31-May-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>19.664</td>
<td>871</td>
<td>9.291</td>
<td>1.664</td>
<td>1.756</td>
<td>3.747</td>
<td>19.1%</td>
</tr>
<tr>
<td>7-Jun-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>20.832</td>
<td>871</td>
<td>9.329</td>
<td>1.664</td>
<td>1.519</td>
<td>2.778</td>
<td>13.3%</td>
</tr>
<tr>
<td>14-Jun-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>21.603</td>
<td>871</td>
<td>9.273</td>
<td>1.664</td>
<td>1.299</td>
<td>2.283</td>
<td>10.6%</td>
</tr>
<tr>
<td>21-Jun-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>22.318</td>
<td>691</td>
<td>8.724</td>
<td>1.664</td>
<td>1.300</td>
<td>1.936</td>
<td>8.7%</td>
</tr>
<tr>
<td>28-Jun-15</td>
<td>35.251</td>
<td>0</td>
<td>35.251</td>
<td>22.506</td>
<td>591</td>
<td>8.768</td>
<td>1.664</td>
<td>1.532</td>
<td>1.372</td>
<td>6.1%</td>
</tr>
<tr>
<td>5-Jul-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>22.991</td>
<td>591</td>
<td>7.852</td>
<td>1.664</td>
<td>1.419</td>
<td>2.212</td>
<td>9.6%</td>
</tr>
<tr>
<td>12-Jul-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>22.882</td>
<td>591</td>
<td>7.820</td>
<td>1.664</td>
<td>1.440</td>
<td>2.332</td>
<td>10.2%</td>
</tr>
<tr>
<td>19-Jul-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>22.396</td>
<td>691</td>
<td>7.784</td>
<td>1.664</td>
<td>1.618</td>
<td>2.776</td>
<td>12.4%</td>
</tr>
<tr>
<td>26-Jul-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>22.233</td>
<td>871</td>
<td>7.849</td>
<td>1.664</td>
<td>1.442</td>
<td>3.230</td>
<td>14.5%</td>
</tr>
<tr>
<td>2-Aug-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>21.573</td>
<td>871</td>
<td>8.863</td>
<td>1.664</td>
<td>1.422</td>
<td>2.896</td>
<td>13.4%</td>
</tr>
<tr>
<td>9-Aug-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>21.529</td>
<td>871</td>
<td>8.357</td>
<td>1.664</td>
<td>1.600</td>
<td>3.268</td>
<td>15.2%</td>
</tr>
<tr>
<td>16-Aug-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>21.517</td>
<td>871</td>
<td>7.637</td>
<td>1.664</td>
<td>2.103</td>
<td>3.497</td>
<td>16.3%</td>
</tr>
<tr>
<td>23-Aug-15</td>
<td>35.547</td>
<td>0</td>
<td>35.547</td>
<td>20.367</td>
<td>871</td>
<td>8.358</td>
<td>1.664</td>
<td>2.037</td>
<td>3.992</td>
<td>19.6%</td>
</tr>
<tr>
<td>30-Aug-15</td>
<td>35.845</td>
<td>0</td>
<td>35.845</td>
<td>18.568</td>
<td>871</td>
<td>9.606</td>
<td>1.664</td>
<td>1.958</td>
<td>4.920</td>
<td>26.5%</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>35.845</td>
<td>0</td>
<td>35.845</td>
<td>18.313</td>
<td>871</td>
<td>13.618</td>
<td>1.664</td>
<td>1.144</td>
<td>1.977</td>
<td>10.8%</td>
</tr>
<tr>
<td>13-Sep-15</td>
<td>35.845</td>
<td>0</td>
<td>35.845</td>
<td>18.058</td>
<td>871</td>
<td>13.920</td>
<td>1.632</td>
<td>1.213</td>
<td>1.893</td>
<td>10.5%</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, 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

#### Control Area Load and Capacity

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW&lt;sup&gt;1&lt;/sup&gt;</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Demand Response MW&lt;sup&gt;2&lt;/sup&gt;</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>26-Apr-15</td>
<td>44.813</td>
<td>-1.708</td>
<td>43.105</td>
<td>21.899</td>
<td>0</td>
<td>12.493</td>
<td>1.500</td>
<td>1.200</td>
<td>6.013</td>
<td>27.5%</td>
</tr>
<tr>
<td>3-May-15</td>
<td>44.813</td>
<td>-1.656</td>
<td>43.157</td>
<td>21.033</td>
<td>0</td>
<td>12.161</td>
<td>1.500</td>
<td>1.200</td>
<td>7.263</td>
<td>34.5%</td>
</tr>
<tr>
<td>10-May-15</td>
<td>44.813</td>
<td>-1.656</td>
<td>43.157</td>
<td>20.324</td>
<td>0</td>
<td>12.393</td>
<td>1.500</td>
<td>1.200</td>
<td>7.740</td>
<td>38.1%</td>
</tr>
<tr>
<td>17-May-15</td>
<td>44.813</td>
<td>-1.656</td>
<td>43.157</td>
<td>19.556</td>
<td>0</td>
<td>12.437</td>
<td>1.500</td>
<td>1.200</td>
<td>8.464</td>
<td>43.3%</td>
</tr>
<tr>
<td>24-May-15</td>
<td>44.813</td>
<td>-1.656</td>
<td>43.157</td>
<td>19.278</td>
<td>0</td>
<td>11.952</td>
<td>1.500</td>
<td>1.200</td>
<td>9.227</td>
<td>47.9%</td>
</tr>
<tr>
<td>31-May-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.677</td>
<td>0</td>
<td>11.604</td>
<td>1.500</td>
<td>1.200</td>
<td>7.763</td>
<td>37.5%</td>
</tr>
<tr>
<td>7-Jun-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.724</td>
<td>0</td>
<td>12.488</td>
<td>1.500</td>
<td>1.200</td>
<td>6.832</td>
<td>33.0%</td>
</tr>
<tr>
<td>14-Jun-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.892</td>
<td>0</td>
<td>11.837</td>
<td>1.500</td>
<td>1.200</td>
<td>7.315</td>
<td>35.0%</td>
</tr>
<tr>
<td>21-Jun-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.842</td>
<td>0</td>
<td>10.650</td>
<td>1.500</td>
<td>1.200</td>
<td>8.552</td>
<td>41.0%</td>
</tr>
<tr>
<td>28-Jun-15</td>
<td>44.813</td>
<td>-2.064</td>
<td>42.749</td>
<td>20.745</td>
<td>0</td>
<td>11.198</td>
<td>1.500</td>
<td>1.200</td>
<td>8.106</td>
<td>39.1%</td>
</tr>
<tr>
<td>5-Jul-15</td>
<td>44.813</td>
<td>-2.064</td>
<td>42.749</td>
<td>20.959</td>
<td>0</td>
<td>12.299</td>
<td>1.500</td>
<td>1.200</td>
<td>6.791</td>
<td>32.4%</td>
</tr>
<tr>
<td>12-Jul-15</td>
<td>44.813</td>
<td>-2.064</td>
<td>42.749</td>
<td>21.052</td>
<td>0</td>
<td>11.708</td>
<td>1.500</td>
<td>1.200</td>
<td>7.289</td>
<td>34.6%</td>
</tr>
<tr>
<td>19-Jul-15</td>
<td>44.813</td>
<td>-2.064</td>
<td>42.749</td>
<td>20.568</td>
<td>0</td>
<td>11.430</td>
<td>1.500</td>
<td>1.200</td>
<td>8.051</td>
<td>39.1%</td>
</tr>
<tr>
<td>26-Jul-15</td>
<td>44.813</td>
<td>-2.064</td>
<td>42.749</td>
<td>20.477</td>
<td>0</td>
<td>10.731</td>
<td>1.500</td>
<td>1.200</td>
<td>8.841</td>
<td>43.2%</td>
</tr>
<tr>
<td>2-Aug-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>21.063</td>
<td>0</td>
<td>10.892</td>
<td>1.500</td>
<td>1.200</td>
<td>8.099</td>
<td>38.5%</td>
</tr>
<tr>
<td>9-Aug-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>21.090</td>
<td>0</td>
<td>11.795</td>
<td>1.500</td>
<td>1.200</td>
<td>7.159</td>
<td>33.9%</td>
</tr>
<tr>
<td>16-Aug-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.959</td>
<td>0</td>
<td>11.605</td>
<td>1.500</td>
<td>1.200</td>
<td>7.480</td>
<td>35.7%</td>
</tr>
<tr>
<td>23-Aug-15</td>
<td>44.813</td>
<td>-2.069</td>
<td>42.744</td>
<td>20.933</td>
<td>0</td>
<td>11.665</td>
<td>1.500</td>
<td>1.200</td>
<td>7.386</td>
<td>35.2%</td>
</tr>
<tr>
<td>30-Aug-15</td>
<td>44.813</td>
<td>-2.079</td>
<td>42.734</td>
<td>21.386</td>
<td>0</td>
<td>12.299</td>
<td>1.500</td>
<td>1.200</td>
<td>6.349</td>
<td>29.7%</td>
</tr>
<tr>
<td>6-Sep-15</td>
<td>44.813</td>
<td>-2.079</td>
<td>42.734</td>
<td>21.132</td>
<td>0</td>
<td>12.287</td>
<td>1.500</td>
<td>1.200</td>
<td>6.615</td>
<td>31.3%</td>
</tr>
<tr>
<td>13-Sep-15</td>
<td>44.813</td>
<td>-2.079</td>
<td>42.734</td>
<td>21.363</td>
<td>0</td>
<td>11.287</td>
<td>1.500</td>
<td>1.200</td>
<td>7.384</td>
<td>34.6%</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. The Demand Response programs are utilized during the Winter Capacity period.
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.

NPCC Glossary of Terms

Capacity: The rated continuous load-carrying ability, expressed in MW or MVA of generation, transmission, or other electrical equipment.

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 (SCC) and generation anticipated to be commercial for the identified capacity period.

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 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/Constraints**
This is the reduction in Capacity caused by forecasted generator maintenance outages and by any additional forecasted transmission or by other constraints causing internal bottling within the Reliability Coordinator area. Some Reliability Coordinator areas may 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 outages as reported on 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 generator maintenance, derating, plus generation bottling.

Québec
This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include – usually in summer – 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 plus 50 percent of the second largest contingency.

New England
The required operating reserve consists of 125 percent of the first largest contingency plus 50 percent of the second largest contingency.

New York
The required operating reserve consists of 150 percent of the largest generator contingency.

Ontario
The required operating reserve consists of 100 percent of the first largest contingency plus 50 percent of the second largest contingency.
Québec
The required operating reserve consists of 100 percent of the largest first contingency + 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 based on five years of historical unplanned outage data and will also include gas at risk values.

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/Constraints – 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). 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.

Though this is primarily impactive in the summer capacity period, it is determined for both the summer and winter capacity analysis. The Bottled Resources calculation takes into account the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC.

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 Total Transfer Capability under Forecasted Summer Conditions

The following table represents the transfer capabilities between Reliability Coordinator areas represented as Total Transfer Capabilities (TTC). It is recognized that the actual transfer capability may differ depending on system conditions or configurations such as actual voltage profiles, operating conditions, etc. The transfer values represent an expected transfer capability under the peak demand scenario with the assumed transmission configuration identified in this report. It is based on historical operating experience and known operating constraints in each Reliability Coordinator area. The total for each Reliability Coordinator area represents the simultaneous transfer between Reliability Coordinator areas that may be achievable. 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.

### Transfers from Maritimes to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eel River (NB)/Matapédia (QC)</td>
<td>335/400</td>
<td>335/350</td>
<td>Eel River HVDC (capable of 350 MW) reduced by 15 MW due to losses.</td>
</tr>
<tr>
<td>Edmundston (NB)/Madawaska (QC)</td>
<td></td>
<td></td>
<td>Madawaska HVDC derated to 350 MW due to temperature. (30 °C / 86 °F). At the present time the NB to HQ-HVDC transfer capability is limited to and posted at 525 MW due to Load loss limitations in the Maritimes. This limit will be reviewed post MPRP project completion.</td>
</tr>
<tr>
<td>Total</td>
<td>735</td>
<td>685</td>
<td></td>
</tr>
</tbody>
</table>

| New England           |                                     |                                     |                                  |
| Keswick (3001 line), Point Lepreau (390/3016 line) | 1000                                | 1000                                | The 1,000 MW limit is dependent on the completion on the MPRP project. 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 margin. |
| Total                 | 1000                                | 1000                                |                                  |
Transfers from New England to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keswick (3001 line),</td>
<td>550</td>
<td>550</td>
<td>Transfer capability is dependent upon operating conditions in northern Maine and the Maritimes. If key generation or capacitor banks are not operational, the transfer from New England to New Brunswick will be decreased. At the time this report was completed the following procedure was in place; The NBP-SO has limited the TTC (under specified conditions) to 200 MW but will increase it to 550 MW upon 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 it is presently under review pending completion of the MPRP project. For resource adequacy studies, NE assumes that it can export 550 MW of capacity to meet New Brunswick loads with 50 MW of margin for real-time balancing control margin.</td>
</tr>
<tr>
<td>Point Lepreau (390/3016 line)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>550</td>
<td>550</td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern AC Ties</td>
<td>1,310</td>
<td>1,310</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 1,310 MW. ISO-NE planning assumptions are based on an interface limit of 1,310 MW.</td>
</tr>
<tr>
<td>(393, 398, E205W, PV20, K7, K6 and 690 lines)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NNC Cable (601, 602 and 603 cables)</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>Total</td>
<td>1,840</td>
<td>1,840</td>
<td></td>
</tr>
</tbody>
</table>
### Québec

<table>
<thead>
<tr>
<th>Description</th>
<th>Capacity 1</th>
<th>Capacity 2</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<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 transfer capability is limited by the DOE and system conditions in Vermont, at times 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 at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New England</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern AC Ties</td>
<td>1,400</td>
<td>1,400</td>
<td>Feasible Simultaneous Transfer to New England on free flowing ties.</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><strong>1,930</strong></td>
<td><strong>1,930</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Ontario</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East / D Lines L33P, L34P</td>
<td>300</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>Niagara / A Lines PA301, PA302, BP76, PA27</td>
<td>1,500</td>
<td>1,500</td>
<td>Thermal limits on the QFW interface may restrict imports to lesser values when the generation in the Niagara area is taken into account.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,800</strong></td>
<td><strong>1,800</strong></td>
<td></td>
</tr>
<tr>
<td><strong>PJM</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYC/PJM Linden VFT</td>
<td>315</td>
<td>315</td>
<td>Feasible Simultaneous Transfer to PJM on peak.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,615</strong></td>
<td><strong>1,615</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cedards / Quebec</td>
<td>40</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Chatteauguay (QC)/Massena (NY)</td>
<td>1000</td>
<td>1000</td>
<td></td>
</tr>
<tr>
<td>------------------------------</td>
<td>------</td>
<td>------</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,040</strong></td>
<td><strong>1,040</strong></td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from Ontario to Interconnection Point TTC at Interconnection Points (MW) TTC under Specified Conditions (MW) Rationale for Transfer Capability

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East / D Lines L33P, L34P</td>
<td>300</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>Niagara / A Lines PA301, PA302, BP76, PA27</td>
<td>1,500</td>
<td>1,500</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,800</td>
<td>1,800</td>
<td></td>
</tr>
<tr>
<td><strong>MISO Michigan</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines L4D, LS1D, J5D, B3N</td>
<td>1,650</td>
<td>1,650</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,650</td>
<td>1,650</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>95</td>
<td>95</td>
<td>The 95 MW reflects an agreement through the TE-IESO Interconnection Committee pending further study of available options resulting from the Outaouais Interconnection.</td>
</tr>
<tr>
<td>Ottawa / BRY – PGN Lines X2Y, Q4C</td>
<td>120</td>
<td>32</td>
<td>Circuit Q4C is capable of transferring 120 MW less ½ of Chat Falls generation that is considered in the Québec Installed Capacity (120-88=32). There is no capacity to export to Québec through Lines P33C and X2Y.</td>
</tr>
<tr>
<td>Ottawa / Brookfield Lines D5A, H9A</td>
<td>110</td>
<td>110</td>
<td>Only one of H9A or D5A can be in service at any time. The 110 MW reflects the maximum load that can be transferred to Ontario from Québec (Papier Masson Inc). DSA’s transfer capability is 200 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>1,250</td>
<td>Normally Ontario will schedule up to 1,230 MW allowing for a Transmission Reliability Margin of 20 MW.</td>
</tr>
<tr>
<td>---------------------------</td>
<td>-------</td>
<td>-------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,045</strong></td>
<td><strong>1,957</strong></td>
<td></td>
</tr>
<tr>
<td>MISO Manitoba, Minnesota</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NW / MAN Lines K21W, K22W</td>
<td>288</td>
<td>288</td>
<td></td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>150</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>438</strong></td>
<td><strong>438</strong></td>
<td>Feasible Simultaneous Transfer to Mid-Continent Area Power Pool (MAPP).</td>
</tr>
</tbody>
</table>
## Transfers from Québec to ¹

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maritimes</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Matapédia (QC)/Eel River (NB)</td>
<td>350 + radial loads</td>
<td>350 + radial loads</td>
<td>Radial load transfer amount is dependent on local loading and is updated monthly: May – 42 MW, June – 37 MW, July – 32 MW, August – 35 MW, September – 36 MW.</td>
</tr>
<tr>
<td>Madawaska (QC)/Edmundston (NB)</td>
<td>391 + radial loads</td>
<td>350 + radial loads</td>
<td>Madawaska HVDC derated to 350 MW due to temperature. (30 °C / 86 °F) plus available radial load transfers. Radial load transfer amount is dependent on local loading and is updated monthly: May – 126 MW, June – 116 MW, July - 120 MW, August – 120 MW, September – 133 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>741 + radial loads</td>
<td>700 + radial loads</td>
<td></td>
</tr>
<tr>
<td><strong>New England</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NIC / CMA HVDC link</td>
<td>2,000</td>
<td>1,400</td>
<td>Capability of the facility is 2,000 MW; At certain times, flows over this tie can be limited to 1,400MW in order to respect operating agreements regarding largest single loss of source.</td>
</tr>
<tr>
<td>Bedford (BDF) – Highgate (VT)</td>
<td>225</td>
<td>225</td>
<td>Capacity of the Highgate HVDC facility is 225 MW</td>
</tr>
<tr>
<td>Line 1429</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stanstead (STS) – Derby (VT)</td>
<td>50</td>
<td>35</td>
<td>While voltage limits allow 80 MW to be transferred, normally only 35 MW of load in New England is connected.</td>
</tr>
<tr>
<td>Line 1400</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,275</td>
<td>1,660</td>
<td></td>
</tr>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chateauguay (QC)/Massena (NY)</td>
<td>1,800</td>
<td>1,500</td>
<td>Beauharnois G.S. is used for Québec needs under peak load conditions, in which case transfer is limited to Châteauguay capacity. The maximum capacity in this path is 1,800 MW. This capacity is limited by the maximum allowable short-circuit current of the Châteauguay facilities. It may also be limited by the maximum import capacity of the New York grid, which ranges from 1,500 to 1,800 MW.</td>
</tr>
</tbody>
</table>

---

¹ For New England and New York, the transfer capability is limited to 1,400 MW. For Maritimes, the transfer capability is limited to 350 MW due to temperature. (30 °C / 86 °F) plus available radial load transfers. Radial load transfer amount is dependent on local loading and is updated monthly.
The FTC is 325 MW less projected peak Cornwall load of 145 MW tapped off the circuit.

Québec to New York transfer capability may reach 1,990 MW on an hour-ahead basis and depending on operating conditions in New York and in Québec.

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
<th>New York Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Les Cèdres (Qc)/Dennison (NY)</td>
<td>190</td>
<td>180</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,990</strong></td>
<td><strong>1,680</strong></td>
</tr>
</tbody>
</table>

**Ontario**

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beauharnois (Qc)/St-Lawrence (Ont.)</td>
<td>800</td>
<td>800</td>
</tr>
<tr>
<td>Brookfield/Ottawa (Ont.)</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Rapide-des-Iles (Qc)/Dymond (Ont.)</td>
<td>55</td>
<td>55</td>
</tr>
<tr>
<td>Bryson-Paugan (Qc)/Ottawa (Ont.)</td>
<td>431</td>
<td>335</td>
</tr>
<tr>
<td>Outaouais (Qc)/Hawthorne (Ont.)</td>
<td>1,250</td>
<td>1,250</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,736</strong></td>
<td><strong>2,640</strong></td>
</tr>
</tbody>
</table>

**Note 1:** These capabilities may not exactly correspond to other numbers posted in Hydro-Québec’s Annual Reports or on TransÉnergie’s website. Such numbers—usually corresponding to winter ratings—are maximum import/export capabilities available at any one time of the year. The present assessment focuses on summer conditions and these limits recognize transmission or generation constraints in both Québec and its neighbors for the 2015 Summer Operating Period.
## Transfers from Regions External to NPCC

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>TTC under Specified Conditions (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MISO (Michigan) / ONT</strong> Lines L4D, L51D, J5D, B3N</td>
<td>1,600</td>
<td>1,600</td>
<td>Represents a worst case scenario for the implementation of Policy on operation.</td>
</tr>
<tr>
<td>Total</td>
<td>1,600</td>
<td>1,600</td>
<td>Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.</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>288</td>
<td>288</td>
<td></td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>100</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>388</strong></td>
<td><strong>388</strong></td>
<td>Feasible Simultaneous Transfer to Ontario.</td>
</tr>
<tr>
<td><strong>PJM / New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AC Ties</td>
<td>2,450</td>
<td>2,450</td>
<td>Feasible Simultaneous Transfer to New York.</td>
</tr>
<tr>
<td>PJM/NYC Linden VFT</td>
<td>315</td>
<td>315</td>
<td></td>
</tr>
<tr>
<td>PJM/Neptune Neptune Cable</td>
<td>660</td>
<td>660</td>
<td></td>
</tr>
<tr>
<td>PJM/NYC HTP DC/DC Tie</td>
<td>660</td>
<td>660</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,085</strong></td>
<td><strong>4,085</strong></td>
<td></td>
</tr>
</tbody>
</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% 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. Wind projected capacity is derated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and 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 LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

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

**New England**

ISO New England’s energy model is an annual model of ISO-NE Area total energy, 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, and produces forecasts of weekly, monthly, and seasonal peak loads over a 10 year time 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 non-holiday weekdays). A reasonable approximation for “normal weather” associated with the winter peak is 7.0 °F and for the summer peak is 90.2 °F. The extreme demand forecast, which has a 10 percent chance of being exceeded, is associated with the winter peak of 1.6 °F and summer peak of 94.2 °F. Additional information describing ISO New England’s load forecasting may be found at [http://www.iso-ne.com/trans/celt/fsct_detail/index.html](http://www.iso-ne.com/trans/celt/fsct_detail/index.html).

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. An example would be when the Boston zone is forecasted to be sixty five degrees while the Hartford area is forecasting ninety degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The eight zones are then summed for a total New England load. This adds an additional New England load forecast to our Advanced Neural Network models (ANN) and our Similar Day Analysis (SimDays). Accuracy for this zonal forecast has been an improvement since the summer of 2013.

**New York**

The NYISO employs a two-stage process in developing load forecasts for each of the 11 zones within the NYCA. In the first stage, zonal load forecasts are based upon econometric projections prepared in March 2015. 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.

The economic assumptions are for modest growth in peak demand, based on projections for 2015 provided to the NYISO in January 2015.

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 (NYP), 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 Group, a part of the New York Department of Public Service staff reporting to the New York Public Service Commission.

The weather-normalized 2014 peak was 33,291 MW, 375 MW (1.11%) lower than the forecast of 33,666 MW prepared in December 2013. The current 2015 peak forecast is 33,567 MW and was updated in December 2014. It is lower than the December 2013 forecast by 99 MW (0.29%). This is attributed to a decrease in industrial load in an upstate area; annual growth rates in other areas of the state were the same or nearly the same as last year. There are two higher-than-expected scenarios forecast. One is a forecast without the impacts of energy efficiency programs or behind-the-meter solar photovoltaic generation. The high growth forecast for the summer of 2015 is 33,890 MW. The second is a forecast based on extreme weather conditions, set to the 90th percentile of typical peak-producing weather conditions. The extreme weather forecast for 2015 is 35,862 MW.

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 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 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.

The Ontario demand forecast uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers, including weather effects, economic and demographic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. 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\(^{12}\) scenario, Ontario uses the maximum value from the sorted history.

The wind capacity in Table 4 is the total installed capacity expected during the operating period, with the wind resources expected in service outlined in Table 3. 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 factor for winter is 29.9 percent, for summer 8.0 percent, and 21.7 percent during shoulder months.

\(^{12}\) Additional information describing Ontario’s demand forecasting may be found at http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2015mar.pdf
Québec

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

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or 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 44-year database of temperatures (1971-2014), adjusted by 0.3 °C (0.5 °F) per decade starting in 1971 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 294 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of these 294 scenarios. 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, expressed as a percentage of standard deviation over total load, is lower during the summer than during the winter. As an example, at the summer peak, weather conditions uncertainty is about 450 MW, equivalent to one standard deviation. During winter, this uncertainty is 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.

- **Note:** Directory #1 is presently being revised by the NPCC Task Forces on Coordination of Operation and Coordination of Planning.

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.
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:** Review is underway to check continued need for the document based on content in corresponding NERC Standard (MOD - 025-1).

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:** Review is underway to check continued need for the document based on content in corresponding NERC Standard (MOD - 025-1).

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*

- **Note:** Procedure Document C-01 has been merged with Procedure Document C-36.

*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.

- **Note:** TFCO currently has this document under review.

*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-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

Hydro Quebec

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
   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
Appendix VII - References

CP-8 2015 Summer Multi-Area Probabilistic Reliability Assessment
NPCC Reliability Assessment for Summer 2015
Appendix VIII – CP-8 2015 Summer Multi-Area Probabilistic Reliability Assessment – Supporting Documentation
Northeast Power Coordinating Council, Inc.
Multi-Area Probabilistic Reliability Assessment
For
Summer 2015

April 29, 2015

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

Following activation of demand response resources, use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not expected during the 2015 summer period for the Base Case conditions assumed for the expected load forecast assumptions.

Operating procedures are available, as required, to maintain reliability for the unlikely simultaneous combination of severe system conditions (such as reductions in anticipated transfers, maintenance extending into the summer period and/or additional constraints) materializing coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>FOREWORD</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>Base Case Results</td>
<td>4</td>
</tr>
<tr>
<td>Severe Case Results</td>
<td>5</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>9</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>11</td>
</tr>
<tr>
<td>Generation</td>
<td>13</td>
</tr>
<tr>
<td>Wind Resource Modeling</td>
<td>14</td>
</tr>
<tr>
<td>Unit Availability</td>
<td>15</td>
</tr>
<tr>
<td>Transfer Limits</td>
<td>16</td>
</tr>
<tr>
<td>Operating Procedures to Mitigate Resource Shortages</td>
<td>18</td>
</tr>
<tr>
<td>Assistance Priority</td>
<td>19</td>
</tr>
<tr>
<td>Modeling of Neighboring Regions</td>
<td>20</td>
</tr>
<tr>
<td>ANALYSIS</td>
<td>23</td>
</tr>
<tr>
<td>Summer 2014 Review</td>
<td>23</td>
</tr>
<tr>
<td>2015 Base Case Results</td>
<td>26</td>
</tr>
<tr>
<td>Base Case Assumptions</td>
<td>27</td>
</tr>
<tr>
<td>2015 Severe Case Results</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

A) OBJECTIVE AND SCOPE OF WORK .......................................................... 36

B) EXPECTED NEED FOR OPERATING PROCEDURES .......................... 38
   Table 7  Base Case ........................................................................... 38
   Table 8  Severe Case ...................................................................... 39

C) MULTI-AREA RELIABILITY SIMULATION PROGRAM DESCRIPTION 40
EXECUTIVE SUMMARY

Introduction
This study assessed NPCC Area reliability by estimating the projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2015 (May through September). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2015", April 2015. ¹

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

Base Case Results
For the May - September 2015 period, assuming the Base Case conditions for the expected load level and following activation of demand response resources, Figures EX-1(a) shows there would be no significant likelihood of implementing the identified operating procedures (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve, etc.) in response to a capacity deficiency for the expected load forecast. The expected load forecast is based upon the probability-weighted average of the seven load levels simulated.

¹ See: http://www.npcc.org/seasonal.asp?Folder=CurrentYear
Figure EX-1(b) shows, following activation of demand response resources, the likelihood of reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve under the Base Case conditions for the extreme load forecast (represents the second to highest load level, having approximately a 6% chance of occurring).

Severe Case Results
For the May - September 2015 period, Figure EX-1(c) shows, following activation of demand response resources, the expected use of the indicated operating procedures assuming the Severe Case conditions and the expected load forecast.
For the May - September 2015 period, Figure EX-1(d) shows, following activation of
demand response resources, the expected use of the indicated operating procedures
assuming the Severe Case conditions and the extreme load forecast.

![Expected Use of Indicated Operating Procedures for Summer 2015
Considering Severe Case Assumptions (May – September)
(Extreme Load Forecast)]

Conclusions
Following activation of demand response resources, there would be no significant
likelihood of using operating procedures designed to mitigate resource shortages
(reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) during
the 2015 summer period for the Base Case conditions assumed for the expected load
forecast assumptions. Only New York and New England show the need to use these
operating procedures under the Base Case conditions for the extreme load forecast
(represents the second to highest load level, having approximately a 6% chance of occurring).

Figures EX-1(c) (expected load level) and EX-1(d) (extreme load level) show, following
activation of demand response resources, the possible range of operating procedure if
reductions in anticipated transfers, maintenance extending into the summer period and/or
additional constraints materialize coincident with higher than expected loads (such as
caused by a wide spread, prolonged heat wave with high humidity and near record
temperatures).

Operating procedures are available, as required, to maintain system reliability for this
unlikely simultaneous combination of extreme weather and severe system conditions.
INTRODUCTION

This study assessed the short-term reliability of Northeast Power Coordinating Council, Inc. (NPCC) for summer 2015 by estimating use of Area operating procedures to mitigate resource shortages for the May and September months. The Working Group closely coordinated its efforts with the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2015", April 2015.

The development of this Working Group’s assessment was in response to recommendation (5) from the "June 1999 Heat Wave – NPCC Final Report", August 1999 that states:

“The NPCC Task Force on Coordination of Planning (TFCP) should explore the use of a multi-area reliability study tool as a part of an annual resource adequacy review to gain insight into the effects of maintenance schedules and transmission constraints on regional reliability.”

The database developed for the NPCC CP-8 Working Group's "2014 Long Range Adequacy Overview", December 2, 2014, 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 year 2015 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 3.16 was used in this assessment.

---

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 to model the 2002 load shape. Table 1 summarizes each Area's summer peak load assumptions for the year 2015. The values shown for Québec and the Maritimes Area show both their actual summer peak and the peak during the period of NPCC’s peak.

<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>22,091</td>
<td>24,212</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td>21,035</td>
<td>22,087</td>
<td>August</td>
</tr>
<tr>
<td>Maritimes Area (MT)</td>
<td>3,607</td>
<td>3,939</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td>3,266</td>
<td>3,566</td>
<td>August</td>
</tr>
<tr>
<td>New England (NE)</td>
<td>28,397</td>
<td>31,768</td>
<td>August</td>
</tr>
<tr>
<td>New York (NY)</td>
<td>33,567</td>
<td>36,445</td>
<td>August</td>
</tr>
<tr>
<td>Ontario (ON)</td>
<td>22,991</td>
<td>25,701</td>
<td>July</td>
</tr>
</tbody>
</table>

An explanation of each Area’s expected load forecast and methodology can be found in the companion NPCC CO-12 Working Group Report, “NPCC Reliability Assessment for Summer 2015”, April 2015.

NPCC Areas have different definitions for their extreme peak load forecasts. A brief summary of the basis of each NPCC Area's extreme peak load forecasts follows.

Québec
Expected peak load is based on a reference scenario and average weather conditions. Québec doesn’t forecast “extreme load” per se. For the purpose of this exercise, the “extreme peak” is based on load forecast uncertainty representing approximately two standard deviations. The impact of weather conditions as well as load forecast uncertainty (economic, demographic, prices) are taken into account in simulations.

Maritimes Area
The Maritimes Area doesn’t forecast “extreme load”; however, load forecast uncertainty is modeled in its reliability analysis. The load forecast uncertainty factors are developed by comparing the historical forecast values of load to the actual loads experienced.

3 Extreme peak value based on load forecast uncertainty for referenced peak month.
4 The Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the area administrated by the Northern Maine Independent System Administrator (NMISA).
New England
The Independent System Operator of New England (ISO-NE) bases on a 3-day weighted temperature-humidity index (WTHI) for weather conditions in its peak load forecasts. The peak loads that have a 50% chance of being exceeded and are expected to occur at weighted New England-wide temperature of 90.2F are considered as the 50/50 “reference” case. Peak loads with a 10% chance of being exceeded and expected to occur at a weighted New England-wide temperature of 94.2F, are considered the 90/10 “extreme” case.

New York
The New York Independent System Operator (NYISO) bases its extreme load forecast on “one in 15 year” weather extreme for high temperature. The NYISO characterizes extreme weather conditions in terms of the NYISO summer index, which incorporates dry bulb and dew point values (temperature and humidity), as well as a build-up effect (through lagged elements in the equation).

Ontario
Ontario’s Independent Electricity System Operator (IESO) uses a multivariate econometric model to forecast energy and peak demand on the IESO controlled grid. Demand is defined as loads plus losses and peak demand refers to the highest hourly value.

The IESO does not directly provide a forecast of "extreme load" for this assessment. The IESO determines a value for load forecast uncertainty representing one standard deviation in demand, derived from the impact of temperature, humidity, cloud cover and wind speed on peak demand. The IESO expected demand and IESO load forecast uncertainty values were provided as input to this assessment.

Load Shape
Based on comparison of the results from the previous analyses, and recent weather experience, the Working Group concluded that the 2002 load shape was representative of a reasonable expected coincidence of Area load for summer 2015. The growth rate in each month’s peak was used to escalate Area loads to match the Area's year 2015 demand and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast, except for New England and Ontario, where demand response programs are treated as supply resources modeled in EOP steps. New York and Ontario include energy efficiency programs in the load forecast, but New York demand response (SCR) resources are not included in the load forecast and are treated as supply resources. The New York EDRP program is modeled as an EOP step, and is also not included in the load forecast.

Figure 1(a) shows the diversity in the NPCC Area load shapes used in this analysis for the composite load shape, which assumes the 2002 load shape for the summer period.
Figure 1 (a) shows the forecast daily summer peaks (June through August) modeled for the summer-peaking NPCC Areas (New England, New York, and Ontario) assuming the 2002 load shape. New England and New York closely track each other, while Ontario shows a similar pattern but with a bit more variation.

2003/04 load shape assumed for the November – March period.
Load Forecast Uncertainty
The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on the associated probabilities of occurrence.

While the per unit variations in Area and sub Area load can vary on a monthly basis, Table 2 shows the values assumed for August, corresponding to the assumed occurrence of the NPCC system peak load (assuming the 2002 load shape). 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 shaded in Table 2.

Table 2
Per Unit Variation in Load Assumed for the Month of August 2015

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Q</td>
</tr>
<tr>
<td>MT</td>
<td>1.1380</td>
</tr>
<tr>
<td>NE</td>
<td>1.2480</td>
</tr>
<tr>
<td>NY</td>
<td>1.1173</td>
</tr>
<tr>
<td>ON</td>
<td>1.1556</td>
</tr>
<tr>
<td>Prob.</td>
<td>0.0062</td>
</tr>
</tbody>
</table>
Appendix VIII - CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

Generation
Tables 3(a) and 3(b) summarize the summer 2015 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Also shown in Table 3(a) is each Area's annual weighted average unit availability percentage, based on each Area’s capacity according to the following relationship:

\[
\text{Annual Weighted Average Availability} \% = (1 - \text{P.O.R.}) \times (1 - \text{F.O.R.})
\]

Where:
- P.O.R. = Total Hours on Planned Outage/Total Number of Hours
- F.O.R. = Total Hours on Forced Outage/Total Number of Hours not on Planned Outage

Table 3(a)
NPCC Capacity and Load Assumptions for Indicated Summer 2015 peak period - MW
Base Case - Expected Load

<table>
<thead>
<tr>
<th></th>
<th>Q 6 (August)</th>
<th>MT (August)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON 7 (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>34,217</td>
<td>7,334</td>
<td>30,720</td>
<td>38,006</td>
<td>28,018</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>-2,215</td>
<td>0</td>
<td>1,237</td>
<td>1,635</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load 8</td>
<td>21,035</td>
<td>3,266</td>
<td>28,397</td>
<td>33,567</td>
<td>22,991</td>
</tr>
<tr>
<td>DR / SCR</td>
<td>0</td>
<td>388</td>
<td>2,385</td>
<td>1,132</td>
<td>528</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>52.1</td>
<td>136.4</td>
<td>20.9</td>
<td>21.5</td>
<td>24.2</td>
</tr>
<tr>
<td>Annual Weighted Average Unit Availability (%)</td>
<td>98.6</td>
<td>91.2</td>
<td>87.3</td>
<td>84.2</td>
<td>87.7</td>
</tr>
<tr>
<td>Scheduled Maintenance 9</td>
<td>0</td>
<td>582 10</td>
<td>2</td>
<td>373</td>
<td>715</td>
</tr>
</tbody>
</table>

6 Capacity shown for Québec adjusted for scheduled maintenance. Annual Weighted Average Unit Availability for Québec does not include scheduled maintenance.
7 Capacity shown for Ontario has been seasonally adjusted.
8 Based on the 2002 Load Shape assumption.
9 Maintenance shown is for the week of the monthly peak load.
10 Includes scheduled maintenance, deratings, and units on lay-up.
Table 3(b)
NPCC Capacity and Load Assumptions for Indicated Summer 2015 peak period - MW
Severe Assumptions Scenario - Extreme Load

<table>
<thead>
<tr>
<th></th>
<th>Q&lt;sup&gt;6&lt;/sup&gt; (August)</th>
<th>MT (August)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON&lt;sup&gt;7&lt;/sup&gt; (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>33,217</td>
<td>6,610</td>
<td>30,720</td>
<td>38,006</td>
<td>27,445</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>-2,215</td>
<td>0</td>
<td>1,237</td>
<td>1,635</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load&lt;sup&gt;8&lt;/sup&gt;</td>
<td>22,087</td>
<td>3,566</td>
<td>31,768</td>
<td>36,445</td>
<td>25,701</td>
</tr>
<tr>
<td>DR / SCR</td>
<td>0</td>
<td>388</td>
<td>2,385</td>
<td>566</td>
<td>528</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>40.4</td>
<td>96.2</td>
<td>8.1</td>
<td>8.8</td>
<td>8.8</td>
</tr>
<tr>
<td>Scheduled Maintenance&lt;sup&gt;9&lt;/sup&gt;</td>
<td>0</td>
<td>582&lt;sup&gt;10&lt;/sup&gt;</td>
<td>2</td>
<td>873</td>
<td>2,353</td>
</tr>
</tbody>
</table>

Note: Reserve Margin calculation includes Demand Response (DR) for New England and Ontario, and Special Case Resources (SCR) for New York.

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
Ontario aggregates wind on a sub-area basis and models as an energy limited unit, utilizing a cumulative probability density function (CPDF). This CPDF, which can vary by month and season, represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs are constructed based on the contribution of wind resources during a 5-hour window that represents the highest contiguous average demand hours for the summer and winter seasons, and for each month of spring and fall. In the absence of sufficient historical (actual) wind production data to confidently estimate expected wind contribution during peak demand hours, both historical and simulated wind production data are utilized for developing the CPDFs.
Ontario also calculates Wind Capacity Contribution (WCC) values, in percentage of installed capacity, are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data and the simulated 10-year historic wind data will continue until 10-years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation.

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.

Unit Availability
Details regarding each NPCC Area’s assumptions for generator unit availability are described in the respective Area’s most recent "NPCC Comprehensive Review of Resource Adequacy", updated for the 2015 summer period as described below.

Ontario
Ontario’s generating unit availability was based on the IESO “18-Month Outlook - An Assessment of the Reliability and Operability of the Ontario Electricity System from April 2015 – September 2016” (published March 23, 2015).

For thermal resources, the capacity values and planned outage schedules for each unit are based on monthly maximum continuous ratings and planned outage information submitted by contained in market participant’s submissions. However, the available capacity states and state transition rates for each existing thermal units are derived based on an 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 as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each zone. Maximum capacity values are based on historical median monthly production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the bottom 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening. For new hydroelectric projects, the maximum capacity value is derived based on the average

---

11 See: [http://www.npcc.org/adequacy.cfm](http://www.npcc.org/adequacy.cfm)
monthly capacity factor at the time of system peak in the zone where the new project is located.

**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 each unit’s historical five-year average of scheduled maintenance. Individual generating unit forced outage assumptions were based on the unit’s historical data and North American Reliability Corporation (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**


**Transfer Limits**

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

The New England internal transmission representation is consistent with assumptions currently being developed for the 2015 New England Regional System Plan.
Figure 2 - Assumed Transfer Limits

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro-Québec can import up to 100 MW from New York. 17

Transfer limits between and within some Areas are indicated in Figure 2 with seasonal ratings (S - summer, W - winter) where appropriate. Details regarding the sub-Area representation for Ontario 18, New York 16, and New England 17 are provided in the respective references. The acronyms and notes used in Figure 2 are defined as follows:

<table>
<thead>
<tr>
<th>Sub-Area</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chur</td>
<td>Churchill Falls</td>
</tr>
<tr>
<td>MANIT</td>
<td>Manitoba</td>
</tr>
<tr>
<td>ND</td>
<td>Nicolet-Des Cantons</td>
</tr>
<tr>
<td>BJ</td>
<td>Bay James</td>
</tr>
<tr>
<td>MN</td>
<td>Minnesota</td>
</tr>
<tr>
<td>MAN</td>
<td>Manicouagan</td>
</tr>
<tr>
<td>NE</td>
<td>Northeast (Ontario)</td>
</tr>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>NOR</td>
<td>Norwalk – Stamford</td>
</tr>
<tr>
<td>BHE</td>
<td>Bangor Hydro Electric</td>
</tr>
<tr>
<td>Md</td>
<td>Montréal</td>
</tr>
<tr>
<td>CMA</td>
<td>Central MA</td>
</tr>
<tr>
<td>W MA</td>
<td>Western MA</td>
</tr>
<tr>
<td>NBM</td>
<td>Millbank</td>
</tr>
<tr>
<td>VT</td>
<td>Vermont</td>
</tr>
<tr>
<td>Que</td>
<td>Québec Centre</td>
</tr>
<tr>
<td>Cdrs</td>
<td>Cedars/Langlois</td>
</tr>
</tbody>
</table>

18 Ontario Transmission System document can be found at: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx.
Operating Procedures to Mitigate Resource Shortages

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

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

Table 4 summarizes the load relief assumptions modeled for each NPCC Area. The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 4 was a reasonable approximation for this analysis.

<table>
<thead>
<tr>
<th>Actions</th>
<th>Q</th>
<th>MT</th>
<th>NE 19</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus Appeals</td>
<td>0</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>394</td>
<td>750 20</td>
<td>0</td>
</tr>
<tr>
<td>SCR Load / Man. Volt. Red.</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.17%</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. Volt. Red. Interruptible Load 21</td>
<td>166</td>
<td>0</td>
<td>426</td>
<td>1.28%</td>
<td>1.40%</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>338</td>
<td>0</td>
<td>527.6</td>
<td></td>
</tr>
<tr>
<td>4. No 10-min Reserves RT-EG 22</td>
<td>750</td>
<td>505</td>
<td>0</td>
<td>0</td>
<td>945</td>
</tr>
<tr>
<td>Appeals / Curtailments</td>
<td>0</td>
<td>0</td>
<td>168</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5. 5% Voltage Reduction No 10-min Reserves</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.70%</td>
<td>0</td>
</tr>
</tbody>
</table>

*Real-Time Demand Resource

19 Values for New England’s Real-Time Demand Resources and Real-Time Emergency Generation have been derated to account for historical availability performance.

20 Modeled capacity representing the derated values for New York’s SCR and EDRP programs

21 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.

22 Real Time Emergency Generation
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 the PJM-RTO and neighboring regions of RFC (Reliability First) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 5 and Figure 3.

**Table 5**

<table>
<thead>
<tr>
<th></th>
<th>PJM-RTO</th>
<th>RFC-OTH</th>
<th>MRO-US</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>155,543</td>
<td>44,209</td>
<td>32,221</td>
</tr>
<tr>
<td>Peak Month</td>
<td>July</td>
<td>July</td>
<td>July</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>179,287</td>
<td>49,308</td>
<td>36,340</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>27.5</td>
<td>15.2</td>
<td>16.2</td>
</tr>
<tr>
<td>Weighted Unit Availability (%)</td>
<td>86.1</td>
<td>85.1</td>
<td>84.9</td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>3,400</td>
<td>2,206</td>
<td>1,700</td>
</tr>
<tr>
<td>Interruptible Load</td>
<td>15,763</td>
<td>3,694</td>
<td>2,692</td>
</tr>
<tr>
<td>No 30-min Reserves</td>
<td>2,765</td>
<td>1,470</td>
<td>1,200</td>
</tr>
<tr>
<td>Voltage Reductions</td>
<td>2,201</td>
<td>1,100</td>
<td>1,100</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>635</td>
<td>736</td>
<td>500</td>
</tr>
<tr>
<td>Appeals</td>
<td>400</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (%)</td>
<td>1.0 +/- 3.64, 8.47, 12.69%</td>
<td>1.0 +/- 3.92, 7.85, 11.77%</td>
<td>1.0 +/- 3.92, 7.85, 11.77%</td>
</tr>
</tbody>
</table>

The diversity between the NPCC monthly peak loads and those of PJM-RTO, RFC-Other, and MRO-US are shown in Figure 3.

---

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.
Appendix VIII - CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

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 Report, January 2015. 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 website. 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.

27 See: http://www.pjm.com/planning.aspx
ANALYSIS

Summer 2014 Review

Much of the contiguous U.S. had near-average August temperatures. However, above-average temperatures were observed along the West Coast, Florida, and parts of New England. Florida had its sixth warmest August on record and Washington had its seventh warmest. Below-average temperatures were observed in parts of the Southwest and the Mid-Atlantic. Virginia had its 10th coolest August on record.

A large portion of the western and central U.S. had above average August precipitation. Montana had its wettest August on record with 3.62 inches of precipitation, 2.31 inches above average. This bested the previous record set in 1968 by 0.64 inch. Seven other states across the Great Basin, Northern Rockies, and Northern Plains had a top 10 wet August. Below-average precipitation was observed across parts of the Southern Plains, Southeast, and Northeast.

During August, several extreme precipitation events impacted different regions of the country. On Long Island, New York, 13.57 inches of precipitation fell at Islip's MacArthur Airport over a 24-hour period spanning August 12th and 13th. This set a new 24-hour precipitation record for the state of New York, surpassing the 11.6 inches that fell in August 2011 at Tannersville, New York, associated Hurricane Irene.

Northeast Region

August was another cooler-than-normal month in the Northeast. The region's average temperature of 66.6 degrees F (19.2 degrees C) was 1.6 degrees F (0.9 degrees C) below normal. Eleven of the region's twelve states saw below-normal temperatures, with departures ranging from -1.3 degrees F (-0.7 degrees C) in New Hampshire to -2.6 degrees F (-1.4 degrees C) in Maryland. Maine was the lone warmer-than-normal state at +0.3 degrees F (+0.2 degrees C). Summer overall was cooler than normal, too. The region's average temperature was 67.3 degrees F (19.6 degrees C), 0.4 degrees below normal. Ten states saw below-normal summer temperatures, with departures ranging from -0.1 degrees F (-0.1 degrees C) in Vermont to -1.1 degrees F (-0.6 degrees C) in Maryland. New Hampshire wrapped up the season at normal. Maine was 0.9 degrees F (0.5 degrees C) warmer than normal, making it the state's 15th warmest summer since recordkeeping began.

The region was slightly drier than normal during August. The Northeast received 3.81 inches (96.77 mm) of rain, 97 percent of normal. Eight states were drier than normal, with departures ranging from 68 percent of normal in Rhode Island to 99 percent of normal in New Jersey. For the wet states, departures ranged from 110 percent of normal

29 Information provided by the Northeast Regional Climate Center.
in Maryland to 123 percent of normal in Delaware. Summer, however, ended on the wet side of normal. The region picked up 13.67 inches (347.22 mm) of rain, 110 percent of normal. Eight states were wetter than normal, with three ranking the month among their top 20 wettest. Those states were: Maine, 10th wettest; New Hampshire, 15th wettest; and New York, 18th wettest. Departures ranged from 101 percent of normal in New Jersey to 122 percent of normal in Maine. Departures for the dry states ranged from 80 percent of normal in Connecticut to 99 percent of normal in West Virginia.

Five percent of the Northeast (parts of New England, Long Island, and West Virginia) was experiencing abnormally dry conditions at the start of August, according to the U.S. Drought Monitor. While conditions improved in some areas, abnormal dryness was introduced in other areas. By month's end, six percent of the region (parts of southern New England, southeastern New York, and West Virginia) was abnormally dry.

Extreme rainfall shattered records and caused significant flash flooding in parts of the Northeast from August 12-13. Numerous roads, including major highways, were submerged under feet of water, leaving cars stranded and leading to dozens of water rescues. Two long-term parking lots at Baltimore-Washington International Airport were partially flooded, as well. Baltimore, MD, saw over 6.30 inches (160.02 mm) of rain on the 12th, making it the highest amount of precipitation for any calendar day that was non-tropical based. Islip, NY, saw 13.51 inches (343.15 mm) of rain on the 13th. This was a 500-year storm event, meaning rainfall of that magnitude is only expected to occur once in a 500-year period. The site set a New York State 24-hour precipitation record (13.57 inches or 344.68 mm of rain fell in 24 hours), had its wettest August on record, and tied its all-time wettest month on record. Portland, ME, received 6.43 inches (163.32 mm) of rain on August 13, making it the greatest daily precipitation for any calendar day that was not associated with a tropical system. In addition, the site picked up 2.57 inches (65.28 mm) of rain from 9 PM to 10 PM, setting a new hourly record. Another 1.64 inches (41.66 mm) of rain fell from 10 PM to 11 PM. The consecutive two-hour rain total of 4.21 inches (106.93 mm) also set a record. Periods of heavy rain from August 20-23 caused flash flooding in several areas. Two weak tornadoes accompanied some of the storms on August 21 in Pennsylvania. On the last day of the month, severe storms produced a tornado in Massachusetts.

**New England**
On Sunday, September 28, 2014, ISO New England implemented Master/Local Control Center Procedure #2 (M/LCC 2), Abnormal Conditions Alert and Operating Procedure #4 (OP#4), Action During a Capacity Deficiency, to manage a deficiency in Operating Reserve. The Morning Report projected an operating reserve surplus of 872 MW, based on the forecast load of 16,380 MW. Actual temperature in Hartford was 3 degrees higher than forecasted, and in Boston the actual temperature was 9 degrees higher than forecasted. The expected net import delivery for the peak hour was 1,874 MW and the actual net imports delivered were 2,076 MW.
In addition to other reductions of capacity on various units, at approximately 18:10, a large unit rated for approximately 600 MW, was forced off line due to a mechanical problem. All available capacity units that could start in less than 2 hours, 238 MW, were ordered on-line. At 18:50, M/LCC 2 was declared due to a capacity deficiency for all of New England. At 19:00, OP#4 Action 1 was entered due to an actual deficiency in 30 minute operating reserve. Action 1 of OP#4 was cancelled at 20:30 and M/LCC 2 was cancelled at 22:00.

**New York**
New York had no Demand Response activations or use of emergency procedures for the entire summer 2014 period.

**Ontario**
For the period May 2014 through September 2014, the weather was significantly milder than normal. In particular, the key summer months of June, July and August were all mild without any sustained heatwave. After correcting for weather, none of the months showed year over year growth.

Table 6 compares each NPCC Area’s actual 2014 summer peak demands against the forecast assumptions.

<table>
<thead>
<tr>
<th>NPCC 2014 Summer Peak Loads Actual versus Forecast – MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002 Load Shape</td>
</tr>
<tr>
<td>Area</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>Québec</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>New England</td>
</tr>
<tr>
<td>New York</td>
</tr>
<tr>
<td>Ontario</td>
</tr>
</tbody>
</table>

30 The reconstituted peak is 26,140 MW, and weather normalized peak is 27,970 MW.
31 Ontario was winter peaking in 2014 for the first time in 10 years due to mild summer weather. With more typical weather, Ontario is expected to be summer peaking in 2015.
2015 Base Case Results
The Working Group modified the 2014 NPCC Long Range Adequacy Overview MARS database for the conditions expected for the year 2015.

Table 7 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during May through September 2015 for the Base Case for all NPCC Areas.

As shown in Figure 4(a), for the May - September 2015 period, following activation of demand response resources, assuming the Base Case conditions and the expected load forecast, it is anticipated there would be no significant likelihood of implementing the indicated operating procedures in response to a capacity deficiency.

Figure 4(a) - Summer 2015 – Expected Use of the Indicated Operating Procedures
Base Case Assumptions, Expected Load Level (May – September)

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

Following activation of demand response resources, only New York and New England show a chance of using their operating procedures shown under the Base Case conditions for the extreme load forecast.
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 Summer 2015, April 2015. The Base Case assumptions are summarized below:

System
- As-Is System for the year 2015
- Transfers allowed between Areas
- 2002 Load Shape adjusted to Area’s year 2015 forecast (expected and extreme assumptions)

Ontario
- Forecast consistent with the IESO’s “18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System From April 2015 to September 2016” (March 23, 2015)\(^\text{12}\)
- 2,543 MW of installed Wind Generation (summer seasonal wind capacity contribution of about 13% at peak)
- Demand Measures modeled as per the 2015-Q1 18-Month Outlook
- Conservation and embedded generation effects modeled as per the 2015-Q1 Outlook

New England
- Seasonal claimed capability is used for generating resources, and capacity supply obligation is used for demand resources and capacity imports.
- existing and planned generation resources based on 2015 CELT report
- demand supply resources based on 2015 3rd Annual Reconfiguration Auction
- capacity import based on 2015 3rd Annual Reconfiguration Auction
New York
- Updated Load Forecast - (NYCA – 33,567 MW; NYC 11,929 MW; LI – 5,593 MW)
- Assumptions consistent with the “New York Control Area Installed Capacity Requirements for the Period May 2015 Through April 2016.”

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
- 333 MW of demand response (interruptible load) available

Québec
- Planned resources and load forecast are consistent with the 2014 Quebec Comprehensive Review of Resource Adequacy for the Summer 2015 period, including ~5,700 MW of maintenance and restrictions;
- Wind generation resources are derated by 100% percent for the Summer peak period;
- ~2,000 MW of sales to neighboring areas

PJM-RTO
- As-Is System for the Summer 2015 period – based on the PJM 2014 Reserve Requirement Study
- 2002 Load Shapes & Load Forecast Uncertainty adjusted to the 2015 forecast provided by PJM
- Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)
- ~2,500 MW of high ambient temperature generator derates

RFC ‘Other’
- As-Is System for the Summer 2015 period – based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff.
- 2002 Load Shapes and Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM
- Operating Reserve 2,206 MW (30-min. 1,470 MW; 10-min. 736 MW)

MRO-US
- As-Is System for the Summer 2015 period - based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff.
- 2002 Load Shapes and Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM
- Operating Reserve 1,700 MW (30-min. 1,200 MW; 10-min. 500 MW)

---

33 “RFC Other” refers to the RFC and SERC portions of MISO.
34 MRO-US refers to the MRO portion of MISO.
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 15 - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2015 – 2016 Capability Year" 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.16

The capacity rating for each thermal generating unit is based on its Dependable Maximum Net Capability (DMNC) values from the “2014 Load & Capacity Data of the NYISO” (Gold Book).35 The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Additionally, each generating resource has an associated capacity CRIS (Capacity Resource Interconnection Service) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled.

Existing Resources
All in-service New York generation resources were modeled; the following units have returned to service:

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ravenswood GT 3-4</td>
<td>31.2</td>
<td>Zone J</td>
</tr>
<tr>
<td>Danskammer Units 1-4</td>
<td>493.6</td>
<td>Zone G</td>
</tr>
<tr>
<td>Binghamton CoGen</td>
<td>41.2</td>
<td>Zone C</td>
</tr>
<tr>
<td>Astoria 2</td>
<td>177.0</td>
<td>Zone J</td>
</tr>
</tbody>
</table>

Retirements
There were two unit retirements (111.7 MW) scheduled during the study period:

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dunkirk 2</td>
<td>75</td>
<td>Zone A</td>
</tr>
<tr>
<td>Ravenswood GT 3-3</td>
<td>36.7</td>
<td>Zone J</td>
</tr>
</tbody>
</table>

Planned Units for 2015
No generator units scheduled to come on-line during the study period.

Wind Modeling
Wind generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate value based on 2013 production data. Characteristics of this data indicate a capacity factor of approximately 14% during the summer peak.

35 See:
hours. A total of 1457.1 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 2013 production data. Characteristics of this data indicate an overall 47% capacity factor during the summer peak hours. A total of 31.5 MW of solar capacity was 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 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 the month of July, 1,132.4 MW (ICAP value) of SCRs were modeled. At the time of the August New York peak, this amount was further discounted by 66% in based on historical availability.

EDRPs are modeled as a 86 MW operating procedure step in July and August and they 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’s ratings were consistent with their summer seasonal capability to be reported for the 2015 CELT report.\(^{36}\)

---

\(^{36}\) See: [http://www.iso-ne.com/system-planning/system-plans-studies/celt](http://www.iso-ne.com/system-planning/system-plans-studies/celt)
Appendix VIII - CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

**Solar Modeling**
The solar resources in the 2015 CELT report are included in this assessment, and their seasonal claimed capabilities are used. ISO New England is the process of developing Behind the Meter (BTM) PV forecast that would further reduce the internal demand. The impact from these BTM PV was not modeled in this assessment.

**Demand Supply Resources**
The passive non-dispatchable demand resources, On-Peak and Seasonal-Peak, are expected to provide ~1,687 MW of load relief during the peak hours. About 638 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.

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

**Ontario Details**
For the purposes of this study, the Base Case assumptions for Ontario are consistent with the IESO “18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System From April 2015 – September 2016” (March 23, 2014).

**Existing Resources**
All in-service Ontario generation resources were modeled.

**Resource Additions**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Zone</th>
<th>Fuel Type</th>
<th>Estimated Effective Date</th>
<th>Project Status</th>
<th>Planned (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thunder Bay Condensing Turbine Project</td>
<td>Northwest</td>
<td>Biomass</td>
<td></td>
<td>Commercial Operation</td>
<td>40</td>
</tr>
<tr>
<td>Adelaide Wind Energy Centre</td>
<td>Southwest</td>
<td>Wind</td>
<td></td>
<td>Commercial Operation</td>
<td>60</td>
</tr>
<tr>
<td>Bornish Wind Energy Centre</td>
<td>Southwest</td>
<td>Wind</td>
<td></td>
<td>Commercial Operation</td>
<td>74</td>
</tr>
<tr>
<td>Grand Renewable Energy Park</td>
<td>Southwest</td>
<td>Wind</td>
<td></td>
<td>Commercial Operation</td>
<td>149</td>
</tr>
</tbody>
</table>
Appendix VIII - CP-8 2015 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Region</th>
<th>Type</th>
<th>Phase</th>
<th>Status</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northland Power Solar Empire</td>
<td>Northeast</td>
<td>Solar</td>
<td>2015-Q1</td>
<td>Construction</td>
<td>10</td>
</tr>
<tr>
<td>Twin Falls</td>
<td>Northeast</td>
<td>Water</td>
<td>2015-Q1</td>
<td>Construction</td>
<td>5</td>
</tr>
<tr>
<td>Adelaide Wind Power Project</td>
<td>West</td>
<td>Wind</td>
<td>2015-Q1</td>
<td>Commissioning</td>
<td>40</td>
</tr>
<tr>
<td>Goshen Wind Energy Centre</td>
<td>Southwest</td>
<td>Wind</td>
<td>2015-Q1</td>
<td>Commissioning</td>
<td>102</td>
</tr>
<tr>
<td>Dufferin Wind Farm</td>
<td>Southwest</td>
<td>Wind</td>
<td>2015-Q1</td>
<td>Commissioning</td>
<td>100</td>
</tr>
<tr>
<td>Jericho Wind Energy Centre</td>
<td>Southwest</td>
<td>Wind</td>
<td>2015-Q1</td>
<td>Commissioning</td>
<td>150</td>
</tr>
<tr>
<td>Goulais Wind Farm</td>
<td>Northeast</td>
<td>Wind</td>
<td>2015-Q2</td>
<td>Construction</td>
<td>25</td>
</tr>
<tr>
<td>Grand Renewable Energy Park</td>
<td>Southwest</td>
<td>Solar</td>
<td>2015-Q2</td>
<td>Commissioning</td>
<td>100</td>
</tr>
<tr>
<td>Bow Lake Phase 1</td>
<td>Northeast</td>
<td>Wind</td>
<td>2015-Q2</td>
<td>Commissioning</td>
<td>20</td>
</tr>
<tr>
<td>K2 Wind Project</td>
<td>Southwest</td>
<td>Wind</td>
<td>2015-Q2</td>
<td>Construction</td>
<td>270</td>
</tr>
<tr>
<td>High Falls Hydropower Development</td>
<td>Northwest</td>
<td>Water</td>
<td>2015-Q2</td>
<td>Pre-NTP</td>
<td>5</td>
</tr>
<tr>
<td>Green Electron Power Project</td>
<td>West</td>
<td>Gas</td>
<td>2015-Q3</td>
<td>Construction</td>
<td>298</td>
</tr>
</tbody>
</table>

**Wind Modeling**

Wind generation is aggregated on a zonal basis and modelled with a cumulative probability density function which represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. For the purposes of this assessment, the IESO assumed that wind generation has a dependable contribution of 13.6% of the installed generation capacity at the time of summer peak months.

**Solar Modeling**

Solar generation is aggregated on a zonal basis and is modelled as load modifiers. The contribution of solar resources is modelled as fixed hourly profiles that vary by month and season.
2015 Severe Case Results

Table 8 - (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during May through September 2014 for the Severe Case Scenario for all NPCC Areas.

Figure 5(a) shows, following activation of demand response resources, the expected use of the indicated operating procedures occurrences under the Severe Case assumptions for the expected load. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

Figure 5(b) shows the corresponding results for the extreme load level (represents the second to highest load level, having approximately a 6% chance of occurring).
Severe Case Assumptions
The Severe Case Scenario assumptions are summarized below:

System
- As-Is System for the year 2015
- Transfers allowed between Areas
- Transfer capability between NPCC and MRO/RFC- ‘Other’ reduced by 50%
- 2002 Load Shape adjusted to Area’s year 2015 forecast (expected and extreme assumptions)

Ontario
- ~1,600 MW of maintenance extended into the summer period
- Hydroelectric capacity and energy 10% lower than the Base Case

New England
- Import capabilities from external tie reduced by 50%
- Maintenance overrun by 4 weeks

New York
- Extended maintenance of 500 MW in the southeastern New York throughout summer
- 50% reduction in effectiveness of SCR and EDRP programs
- 330 MW of reduced transfer capability into Long Island
- 300 MW of reduced transfer capability into New York City from PJM

Maritimes
- Wind capacity is de-rated by half to 455MW during July and August due to calm weather.
- Natural Gas fuelled units is de-rated by half to 145 MW for July and August due to supply disruptions. Dual fuel units are assumed to revert to oil.

Québec
- ~1,000 MW of capacity assumed to be unavailable for the summer peak period.

PJM-RTO 37
- Load forecast uncertainty increased by one percent
- Forced Outage rates increased for all units by one percent
- ~2,500 MW on maintenance extended through the summer period (June-August)
- ~5,000 MW of additional high ambient temperature generator derates (June-August)
- 90% compliance of DR + EE resources

---

37 2014 PJM Reserve Requirement Study (RRS), dated October 9, 2014 - available at:
Conclusions
Following activation of demand response resources, use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not expected during the 2015 summer period for the Base Case conditions assumed for the expected load forecast assumptions. Only New York and New England show the need to use these operating procedures under the Base Case conditions for the extreme load forecast (represents the second to highest load level, having approximately a 6% chance of occurring).

Figures 5(a) (expected load level) and 5(b) (extreme load level), show, following activation of demand response resources, the possible range of operating procedure if reductions in anticipated transfers, maintenance extending into the summer period and/or additional constraints materialize coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

Operating procedures are available, as required, to maintain system reliability for this unlikely simultaneous combination of extreme weather and severe system 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 2015-2016 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 the 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 estimating 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 approved no later than April 30, 2015.

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

A report summarizing the results of the Long-Range Adequacy Overview will be approved no later than December 31, 2015.
Table 7 - Base Case

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</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>Appeal</td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>2002 Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shape</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Expected</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.017</td>
<td>0.006</td>
</tr>
<tr>
<td>June</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>July</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.030</td>
<td>0.009</td>
</tr>
<tr>
<td>2002 Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shape</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Extreme</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.103</td>
<td>0.039</td>
</tr>
<tr>
<td>June</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
<td>-</td>
</tr>
<tr>
<td>July</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.197</td>
<td>0.063</td>
</tr>
</tbody>
</table>

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction; "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load.
### APPENDIX B

#### Table 8 - Severe Case

**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</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>Appeal</td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>2002 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.017</td>
<td>0.006</td>
</tr>
<tr>
<td>June</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>July</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.112</td>
<td>0.038</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.023</td>
<td>0.013</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.129</td>
<td>0.044</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.103</td>
<td>0.039</td>
</tr>
<tr>
<td>2002 Load Shape-Extreme Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
<td>-</td>
</tr>
<tr>
<td>June</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.002</td>
<td>-</td>
</tr>
<tr>
<td>July</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.691</td>
<td>0.272</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.001</td>
<td>-</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.800</td>
<td>0.311</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.800</td>
<td>0.311</td>
</tr>
</tbody>
</table>

Notes:  
"30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction; 
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load.
APPENDIX C

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.

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.

38 See: http://www.geenergyconsulting.com/practice-area/software-products/mars
APPENDIX C

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.

Thermal Units
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.
APPENDIX C

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:

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

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 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.
APPENDIX C

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. Curtable 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.