Northeast Power Coordinating Council
Reliability Assessment
For
Summer 2019

FINAL REPORT
April 17, 2019

Conducted by the
NPCC CO-12 & CP-8 Working Groups
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THE INFORMATION IN THIS REPORT IS PROVIDED BY THE CO-12 OPERATIONS PLANNING WORKING GROUP OF THE NPCC TASK FORCE ON COORDINATION OF OPERATION AND THE CP-8 WORKING GROUP OF THE NPCC TASK FORCE ON COORDINATION OF PLANNING. ADDITIONAL INFORMATION PROVIDED BY RELIABILITY COUNCILS ADJACENT TO NPCC.

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The CP-8 Working Group acknowledges the efforts of Messrs. Eduardo Ibanez, GE Energy Consulting, and Patricio Rocha-Garrido, the PJM Interconnection, and thanks them for their assistance in the CP-8 Working Group analysis.
1. **Executive Summary**

This report is based on the work of the NPCC CO-12 Operations Planning Working Group and focuses on the assessment of reliability within NPCC for the 2019 Summer Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the 2018 Summer Operating Period¹.

Moreover, the NPCC CP-8 Working Group on the Review of Resource and Transmission Adequacy provides a seasonal multi-area probabilistic reliability assessment. Results of this assessment are included as a chapter later in this report and supporting documentation is provided in Appendix VIII.

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 capabilities for the upcoming Summer Operating Period. Necessary strategies and procedures are in place 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 potentially alter the report’s findings.

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 respective report sections. The following **Summary of Findings** addresses the significant points of the report discussion. The findings discussed herein are based on projections of electric demand requirements, available supply resources and the most current transmission configurations. This report evaluates NPCC’s and the associated Balancing Authority (BA) areas’ ability to deal with the differing resource and transmission configurations within the NPCC region, as well as the associated Balancing Authority areas’ preparations to deal with the possible uncertainties identified within this report.

**Summary of Findings**

- The forecasted coincident peak demand for NPCC occurs during the peak week (week beginning July 28, 2019)² is 103,548 MW, as compared to 104,137 MW forecasted during the summer 2018 peak week. The capacity outlook indicates a forecasted Net Margin for that week of 19,884 MW. This equates to a net margin

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, New England, New York, Ontario, and Québec are included in Appendix I.
of 19.2% in terms of the 103,548 MW forecasted peak demand. Unless otherwise noted, all forecasted demand is a normal (50/50) net peak forecast.

- The minimum forecasted NPCC “Revised Net Margin” (including bottled resources) of 12,545 MW (or 12.2%) is expected to occur during the week beginning June 23, 2019. The minimum forecasted NPCC Net Margin, not taking bottled resources of 2,737 MW into account, is expected to occur during the week beginning June 16, 2019.

- During the NPCC forecasted peak week of July 28, 2019, the Area forecasted net margins in terms of forecasted demand ranges from approximately 2,260 MW (7.0%) in New York, to 1,819 MW (56.9%) in the Maritimes.

- When comparing the forecast peak week from the previous summer (beginning July 8, 2018) to this summer’s expected peak week (beginning July 28, 2019) the NPCC installed capacity has increased by 2,231 MW to 163,538 MW. The biggest increases in term of installed capacity come from New England (+869 MW) and Ontario (+1,210 MW).

- The coincident peak demand during the 2018 summer was 103,231 MW, occurring on August 28, 2018 at HE18 EDT.

- The largest forecasted NPCC Revised Net Margin for the 2019 Summer Operating Period of 22,636 MW (27.2%) occurs during the week beginning May 5, 2019.

- The Maritimes Area has forecasted a 2019 summer (excluding April, May and September) peak demand of 3,255 MW for the week beginning July 21, 2019 with a projected net margin of 1,706 MW (52.4%). When compared to the Summer 2018 peak demand forecast, it is an increase of 20 MW. For the purpose of this report any values given by the Maritime Area will exclude the months of April, May and September. This is being done to exclude the possibility of heating load having any impact. Planned Transmission work as well as the planned Point Lepreau outage will affect the transfer capabilities between New Brunswick and New England. MW reductions and timelines are detailed in Table 5-3.

- The New England Area expects to have sufficient resources to meet the 2019 summer peak demand forecast of 25,323 MW, for the week beginning July 28, 2019, with a projected net margin of 3,249 MW (12.8%). This net margin is a 1,047 MW increase from the 2018 net margin forecast and can largely be attributed to new generation resources becoming available prior to the 2019 summer assessment period and the decrease in forecasted net demand. The 2019 summer demand forecast is 406 MW (1.5%) less than the 2018 summer forecast of 25,729 MW and takes into account the demand reductions associated with energy...
efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

- The NYISO anticipates adequate resources to meet demand for the 2019 Summer Operating Period. The current 2019 summer peak forecast is 32,382 MW. It is lower than the previous year’s forecast by 522 MW (1.6%). The lower forecasted growth in demand can largely be attributed to the increasing impact of energy efficiency initiatives and the growth of distributed behind-the-meter energy resources. Much of these impacts are due to New York State’s energy policy programs such as the Clean Energy Fund (CEF), the NY-SUN Initiative, and other programs developed as part of the Reforming Energy Vision (REV) proceeding. Anticipated net margins for the expected summer peak period (June 16 through September 8) range from 1,997 MW to 2,300 MW (6.2% to 7.1%).

- The IESO anticipates adequate resources to meet demand for the 2019 Summer Operating Period. The forecasted Ontario summer peak demand is 22,105 MW for normal weather and 24,478 MW for extreme weather during the week beginning June 30, 2019. The minimum net margin observed during the summer assessment period is 1,429 MW, or 6.6% during the week beginning June 23, 2019. As part of an electricity trade agreement with Québec, in exchange for 500 MW of capacity in the winter months, Ontario will be receiving up to 2.3 terawatt hours of clean import energy annually to help reduce greenhouse gas over peak hours. While the IESO has the option to call on up to 500 MW of capacity from Hydro-Québec for the summer as per the seasonal capacity sharing agreement, no request was made for the 2019 summer.

- The Québec Area forecasted summer peak demand (excluding April, May and September) is 21,005 MW during the week beginning August 11, 2019 with a forecasted net margin of 9,429 MW (44.9%). For the Summer 2019, Installed Capacity is expected to total 46,677 MW for the Québec Area, a 30 MW increase since the Summer 2018 assessment. No particular resource adequacy problems are forecasted and the Québec Area expects to be able to provide assistance to other areas, if needed, up to the transfer capability available.

- NPCC Areas are not expected to use their Operating Procedures designed to mitigate resource shortages during the 2019 summer period for the Base Case conditions assuming the expected peak load forecast. The expected peak load level results were based on the probability-weighted average of the seven load levels simulated. The conclusions of the CP-8 assessment are included as Chapter 9 in this report; the full report is included in Appendix VIII.
2. **Introduction**

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 Operations Planning 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 operating periods or specific conditions as requested by the TFCO.

For the 2019 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 2019 Summer Operating Period. The conclusions of the CP-8 assessment are included as Chapter 9 in this report; the full report is included in Appendix VIII.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator (RC) Area basis. These sensitivities may include temperature variations, capacity factors of renewables generation resources, 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 region.
- 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.

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3 For the purpose of this report, the Summer Operating Period evaluation will include operating conditions from week beginning May 5, 2019 through the week beginning September 22, 2019.
• Coordinated data and modeling assumptions with the NPCC CP-8 Working Group and documented the methodology of each Reliability Coordinator Area in its projection of load forecasts.

• Coordinated with other parallel seasonal operational assessments, including the NERC Reliability Assessment Subcommittee (RAS) 2019 Summer Reliability Assessment.
3. **Demand Forecasts for Summer 2019**

The non-coincident forecasted peak demand for NPCC over the 2019 Summer Operating Period is 104,070 MW. The coincident peak demand of 103,548 MW is expected during the week beginning July 28, 2019. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII, page 10.

Ambient weather conditions are the single most important variable impacting the demand forecasts during the summer months. As a result, each Reliability Coordinator 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 IESO represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. ISO-NE updates the Load Forecast twice daily, on a seven-day time horizon in each forecast. The Load Forecast models are provided with a weather input of an eight-city weighted average dry bulb temperature, dew point, wind speed, cloud cover and precipitation. Zonal load forecasts are produced for the eight Load Zones across New England using the same weather inputs with different locational weightings. The NYISO uses a weather index that relates air temperature, wind speed and humidity 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.

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 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 forecasts. The historical peak demands for each week are indicated by the “Historical Peak Load” markers on the corresponding figures.
Summary of Reliability Coordinator Forecasts

Maritimes

- Summer 2019 Forecasted Peak: 3,255 MW (normal) and 3,484 MW (extreme), week beginning July 21, 2019
- Summer 2018 Forecasted Peak: 3,235 MW, week beginning July 1, 2018
- Summer 2018 Actual Peak: 3,243 MW, on August 28, 2018 at HE16 EDT

Figure 3-1: Maritimes Summer 2019 Weekly Demand Profile

4 The Maritimes Area Historical Peak Load profile data provided is based on the historical monthly peak.
New England

- Summer 2019 Forecasted Peak\(^5\): 25,323 MW (normal) and 27,212 MW (extreme) for the week beginning July 28, 2019. However, it is understood that the actual peak load may occur at any point during the months of June through August 2019 depending on weather conditions.

- Summer 2018 Forecasted Peak: 25,729 MW (normal) and 28,120 MW (extreme), week beginning June 3, 2018 through September 9, 2018

- Summer 2018 Actual Peak: 25,899 MW, on August 29, 2018 at HE17 EDT

\textbf{Figure 3-2: New England Summer 2019 Weekly Demand Profile}

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\(^5\) The summer Peak Load Exposure (PLE) period covers the months of June through August; and was developed to help mitigate the effects of abnormal weather during the scheduling of generator outages and help forecast conservative operable capacity margins. The forecasted 2019 summer peak demand is during the week beginning July 28, 2019.
New York

- Summer 2019 Forecasted Peak: 32,382 MW (normal) and 34,186 MW (extreme) for the NPCC week beginning June 28, 2019. However, it is understood that the actual peak load may occur at any point during the months of June through September 2019 depending on weather conditions.

- Summer 2018 Forecasted Peak: 32,904 MW (normal) and 34,744 MW (extreme) during the months of June through August, 2018

- Summer 2018 Actual Peak: 31,861 MW on August 29, 2018 at HE17 EDT

Figure 3-3: New York Summer 2019 Weekly Demand Profile
Ontario

- Summer 2019 Forecasted Peak: 22,105 MW (normal) and 24,478 MW (extreme), week beginning June 30, 2019
- Summer 2018 Forecasted Peak: 22,002 MW (normal) and 24,458 MW (extreme), week beginning July 8, 2018
- Summer 2018 Actual Peak: 23,240 MW, on September 5, 2018 at HE18 EDT

Figure 3-4: Ontario Summer 2019 Weekly Demand Profile
Québec

- Summer 2019 Forecasted Peak: 21,005 MW, (normal) and 21,535 MW (extreme) week beginning August 11, 2019
- Summer 2018 Forecasted Peak: 20,534 MW, (normal) and 21,084 MW (extreme) week beginning August 12, 2018
- Summer 2018 Actual Peak: 21,448 MW, on July 5, 2018 at HE18 EDT

Figure 3-5: Québec Summer 2019 Weekly Demand Profile
4. **Resource Adequacy**

**NPCC Summary for Summer 2019**

The assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning July 28, 2019 (103,548 MW). Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

In Appendix I, Table AP-1 reflects the NPCC (normal) load and capacity summary for the 2019 Summer Operating Period. Appendix I, Tables AP-2 through AP-6 contain the normal load forecast and capacity summary for each NPCC Reliability Coordinator.

Each entry in Table 4-1 (below) is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinators. It summarizes the load and capacities for the peak week beginning July 28, 2019 compared to the summer 2018 forecasted peak week (beginning July 8, 2018).

**Table 4-1: Resource Adequacy Comparison of Summer 2019 and 2018 Forecasts**

<table>
<thead>
<tr>
<th></th>
<th>2019 Forecast</th>
<th>2018 Forecast</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity (+)</td>
<td>163,538</td>
<td>161,307</td>
<td>2,231</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>1,117</td>
<td>1,264</td>
<td>-147</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
<td>2,439</td>
<td>0</td>
<td>2,439</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>167,094</strong></td>
<td><strong>162,571</strong></td>
<td><strong>4,523</strong></td>
</tr>
<tr>
<td>Demand (-)</td>
<td>103,548</td>
<td>104,137</td>
<td>-589</td>
</tr>
<tr>
<td>Interruptible load (+)</td>
<td>375</td>
<td>2,593</td>
<td>-2,218</td>
</tr>
<tr>
<td>Maintenance/De-rate (-)</td>
<td>26,267</td>
<td>26,614</td>
<td>-347</td>
</tr>
<tr>
<td>Required Reserve (-)</td>
<td>8,719</td>
<td>8,719</td>
<td>0</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>9,051</td>
<td>8,419</td>
<td>632</td>
</tr>
<tr>
<td><strong>Net Margin</strong></td>
<td><strong>19,884</strong></td>
<td><strong>17,275</strong></td>
<td><strong>2,609</strong></td>
</tr>
<tr>
<td>Bottled Resources (-)</td>
<td>4,930</td>
<td>5,219</td>
<td>-289</td>
</tr>
<tr>
<td><strong>Revised Net Margin</strong></td>
<td><strong>14,954</strong></td>
<td><strong>12,056</strong></td>
<td><strong>2,898</strong></td>
</tr>
</tbody>
</table>

*Note: Net Interchange represents purchases and sales with Areas outside of NPCC.*

The Revised Net Margin for the 2019 Summer Capacity Period has increased by 2,898 MW since the previous summer assessment. This adjustment can be mostly attributed to a
reduction of NPCC forecasted demand (-589 MW), an increase in installed capacity for the NPCC area (+2,231 MW) and a reduction of maintenance and derates (-347 MW).

The following sections detail the summer 2019 capacity analysis for each Reliability Coordinator 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 margin. 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. Table 4-2 conveys the Maritimes anticipated operable capacity margins for the normal and extreme load forecasts of the summer assessment period during the Maritimes forecasted peak week.

<table>
<thead>
<tr>
<th>Table 4-2: Maritimes Operable Capacity for 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Summer 2019</strong></td>
</tr>
<tr>
<td>Installed Capacity (+)</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
</tr>
<tr>
<td>Peak Load Forecast (-)</td>
</tr>
<tr>
<td>Operating Margin (MW)</td>
</tr>
<tr>
<td>Operating Margin (%)</td>
</tr>
</tbody>
</table>

**New England**

To determine New England capacity margins, ISO-NE compares an Installed Capacity and Operable Capacity projections, recognizing normal peak demand forecasts and applying
its operating experience to adjust the available capacity, as needed. For example, ISO-NE adjusts the available capacity from natural-gas-fired generation during pipeline maintenance and construction. The capacity margin is evaluated in two ways. The first method is based on the resources obligation from the Forward Capacity Market, referred to as the 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). The second method is based on the seasonal claimed capability (SCC) of the resource. The SCC is recognized as a generator’s maximum output established through seasonal audits and reflected as capacity throughout this report and used in Table 4-1, Table 4-3, Table 4-4 and Appendix AP-1 and AP-3 Tables.

### Table 4-3: New England Installed and Operable Capacity for Normal Forecast

<table>
<thead>
<tr>
<th>Normal Demand Forecast</th>
<th>28 Jul-2019</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSO</td>
</tr>
<tr>
<td>Operable Capacity + Non-Commercial Capacity (+)</td>
<td>30,683</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>1,328</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
<td>430</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>32,441</strong></td>
</tr>
<tr>
<td>Peak Normal Demand Forecast (-)</td>
<td>25,323</td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>0</td>
</tr>
<tr>
<td>Known Maintenance + Derates (-)</td>
<td>18</td>
</tr>
<tr>
<td>Operating Reserve Requirement MW (-)</td>
<td>2,305</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>3,125</strong></td>
</tr>
<tr>
<td><strong>Operable Capacity Margin (%)</strong></td>
<td>12.3</td>
</tr>
</tbody>
</table>

New England also compares Installed Capacity and Operable Capacity with recognizing extreme demand forecasts to further evaluate New England operable-capacity risks. This broadened approach helps Operations identify potential capacity concerns for the upcoming capacity period and prepare for severe demand conditions. The analysis in Table 4-4 below, shows the further reduction in operable capacity margin recognizing these factors. The net interchange in these capacity assessments only takes into account the capacity cleared in capacity markets, which is much lower than actual transmission transfer capabilities. If extreme summer forecast conditions materialize, New England
may need to rely more heavily on import capabilities from neighboring Areas, as well as possible implementation of Emergency Operating Procedures (EOPs). These actions are anticipated to provide sufficient energy or load relief to cover the operable capacity deficiency identified in the Extreme Demand Forecast.

Table 4-4: New England Installed and Operable Capacity for Extreme Forecast

<table>
<thead>
<tr>
<th>Extreme Demand Forecast</th>
<th>28 Jul-2019</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<tr>
<td>Dispatchable DSM (+)</td>
<td>430</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>32,441</strong></td>
</tr>
<tr>
<td>Peak Normal Demand Forecast (-)</td>
<td>27,212</td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>0</td>
</tr>
<tr>
<td>Known Maintenance + Derates (-)</td>
<td>18</td>
</tr>
<tr>
<td>Operating Reserve Requirement MW (-)</td>
<td>2,305</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>1,236</strong></td>
</tr>
<tr>
<td><strong>Operable Capacity Margin (%)</strong></td>
<td><strong>4.5</strong></td>
</tr>
</tbody>
</table>

New England forecasts the 2019 summer peak to occur on the week beginning July 28. The calculation for the operable-capacity margin takes into account summer Peak Load Exposure (PLE), which covers operating periods from the first full week of June through the last full week in August. The PLE was developed and implemented to help mitigate the effects of abnormal weather during generator maintenance and outage scheduling and to support conservative forecasts for the operable-capacity margin.

**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 and grid-connected solar units are counted at nameplate for Installed Capacity and seasonal derates are applied. Net Interchange includes the election of Unforced Capacity Deliverability Rights (UDRs), External CRIS Rights, Existing Transmission Capacity for
Native Load (ETCNL) elections, estimated First Come First Serve Rights (FCFSR), and grandfathered exports. UDR is capacity provided by controllable transmission projects that provide a transmission interface to the New York Control Area (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, solar and refuse, based on historical performance data. The NPCC Operating Reserve Requirement for New York is one-and-a-half times the largest single generating source contingency in the NYCA. The NYISO procures operating reserve of two times (2,620 MW) the largest single generating source contingency to ensure compliance with a New York State Reliability Council Rule. Unplanned Outages are based on expected availability of all generators in the NYCA based on historic availability. Historic availability factors in all forced outages, including those due to weather and availability of fuel.

The values in Table 4-5 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 4-5: New York Operable Capacity Forecast

<table>
<thead>
<tr>
<th>Summer 2019</th>
<th>Normal Forecast (MW)</th>
<th>Extreme Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity (+)</td>
<td>39,452</td>
<td>39,452</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>1,452</td>
<td>1,452</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
<td>1,309</td>
<td>1,309</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>42,213</strong></td>
<td><strong>42,213</strong></td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>1,512</td>
<td>1,512</td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>2,620</td>
<td>2,620</td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>3,445</td>
<td>3,445</td>
</tr>
<tr>
<td>Peak Load Forecast (-)</td>
<td>32,382</td>
<td>34,186</td>
</tr>
<tr>
<td><strong>Operating Margin (MW)</strong></td>
<td><strong>2,260</strong></td>
<td><strong>456</strong></td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td><strong>7.0%</strong></td>
<td><strong>1.3%</strong></td>
</tr>
</tbody>
</table>

**Ontario**

The Ontario reserve requirement is expected to be met for the summer months of 2019 under normal weather conditions. However, there are a number of negative operating margins observed under the extreme demand forecast scenarios. These are not reflected in Table 4-6 as they do not coincide with the peak extreme demand forecast week. This adequacy assessment was made without including potential imports from IESO’s neighboring entities (capability of 5,200 MW) and thus should not be seen as a cause for concern. If the extreme weather conditions do materialize, the IESO may need to reject some generator maintenance outage requests to ensure that Ontario’s demand is met during the summer peak.
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 as well as environmental and regulatory restrictions.

The results in Table 4-7 indicate that occurrences of unserved energy are not expected over the summer 2019 period. Based on these results it is anticipated that Ontario will be energy adequate for the normal weather scenario for the review period.

<table>
<thead>
<tr>
<th></th>
<th>Summer 2019</th>
<th>Normal Forecast</th>
<th>Extreme Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity (+)</td>
<td>38,271</td>
<td>38,271</td>
<td>38,271</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
<td>790</td>
<td>790</td>
<td>790</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>39,061</strong></td>
<td><strong>39,061</strong></td>
<td><strong>39,061</strong></td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>10,767</td>
<td>10,767</td>
<td></td>
</tr>
<tr>
<td>Operating Reserve Requirement (-)</td>
<td>1,401</td>
<td>1,401</td>
<td></td>
</tr>
<tr>
<td>Unplanned Outages (-)</td>
<td>1,901</td>
<td>1,901</td>
<td>1,901</td>
</tr>
<tr>
<td>Peak Load Forecast (-)</td>
<td>22,105</td>
<td>24,478</td>
<td></td>
</tr>
<tr>
<td><strong>Operating Margin (MW)</strong></td>
<td><strong>2,887</strong></td>
<td>514</td>
<td></td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td><strong>13.1%</strong></td>
<td>2.1%</td>
<td></td>
</tr>
</tbody>
</table>
Table 4-7: 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 2019</td>
<td>17,039</td>
<td>10,412</td>
</tr>
<tr>
<td>June 2019</td>
<td>16,986</td>
<td>10,939</td>
</tr>
<tr>
<td>July 2019</td>
<td>17,360</td>
<td>11,911</td>
</tr>
<tr>
<td>Aug 2019</td>
<td>17,534</td>
<td>11,669</td>
</tr>
<tr>
<td>Sept 2019</td>
<td>15,436</td>
<td>10,161</td>
</tr>
</tbody>
</table>

Québec

The Québec Area anticipates adequate resources to meet demand for the 2019 summer season. The current 2019 peak forecast is 21,005 MW and the forecasted operating margin is 9,429 MW for the forecasted peak week, beginning August 11, 2019. This includes known maintenance and derates of 11,880 MW, including scheduled generator maintenance and wind generator derating. Table 4-8 shows the factors included in the operating margin calculation.

Table 4-8: Québec Adequacy Projections for Summer 2019

<table>
<thead>
<tr>
<th>Summer 2019</th>
<th>Normal Load Forecast (MW)</th>
<th>Extreme Load Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity (+)</td>
<td>46,677</td>
<td>46,677</td>
</tr>
<tr>
<td>Net Interchange (+)</td>
<td>-1,663</td>
<td>-1,663</td>
</tr>
<tr>
<td>Dispatchable DSM (+)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td>45,014</td>
<td>45,014</td>
</tr>
<tr>
<td>Interruptible Load (+)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Known Maintenance &amp; Derates (-)</td>
<td>11,880</td>
<td>11,880</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>21,005</td>
<td>21,535</td>
</tr>
<tr>
<td><strong>Operating Margin (MW)</strong></td>
<td><strong>9,429</strong></td>
<td><strong>8,899</strong></td>
</tr>
<tr>
<td><strong>Operating Margin (%)</strong></td>
<td><strong>44.9%</strong></td>
<td><strong>41.3%</strong></td>
</tr>
</tbody>
</table>
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 multi-annual reservoirs (water reserves lasting more than one year). 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 such as the reduction of exports or capacity purchases 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 two consecutive years of low water inflows totalling 64 TWh, or a sequence of four years totalling 98 TWh, and having a 2% 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.\(^7\)

Table 4-9 below summarizes projected capacity and margins by Reliability Coordinator area. Appendix I shows these projections for the entire summer operating period.

### Table 4-9: 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>DDSM MW</th>
<th>Total Capacity MW</th>
<th>Demand 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>28-Jul-19</td>
<td>163,538</td>
<td>1,117</td>
<td>2,439</td>
<td>167,094</td>
<td>103,548</td>
<td>375</td>
<td>26,267</td>
<td>8,719</td>
<td>9,051</td>
<td>19,884</td>
</tr>
<tr>
<td>Maritimes</td>
<td>Peak Week</td>
<td>21-Jul-19</td>
<td>7,809</td>
<td>0</td>
<td>0</td>
<td>7,809</td>
<td>3,255</td>
<td>289</td>
<td>1,967</td>
<td>893</td>
<td>277</td>
<td>1,706</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>22-Sep-19</td>
<td>7,809</td>
<td>0</td>
<td>0</td>
<td>7,809</td>
<td>3,240</td>
<td>303</td>
<td>2,958</td>
<td>893</td>
<td>277</td>
<td>744</td>
</tr>
<tr>
<td></td>
<td>NPCC Peak Week</td>
<td>28-Jul-19</td>
<td>7,809</td>
<td>0</td>
<td>0</td>
<td>7,809</td>
<td>3,196</td>
<td>369</td>
<td>1,993</td>
<td>893</td>
<td>277</td>
<td>1,819</td>
</tr>
<tr>
<td>New England</td>
<td>Peak Week</td>
<td>28-Jul-19</td>
<td>31,329</td>
<td>1,328</td>
<td>340</td>
<td>32,997</td>
<td>25,323</td>
<td>0</td>
<td>20</td>
<td>2,305</td>
<td>2,100</td>
<td>3,249</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>2-Jun-19</td>
<td>31,329</td>
<td>1,270</td>
<td>340</td>
<td>32,939</td>
<td>25,323</td>
<td>0</td>
<td>154</td>
<td>2,305</td>
<td>2,800</td>
<td>2,357</td>
</tr>
<tr>
<td></td>
<td>NPCC Peak Week</td>
<td>28-Jul-19</td>
<td>31,329</td>
<td>1,328</td>
<td>340</td>
<td>32,997</td>
<td>25,323</td>
<td>0</td>
<td>20</td>
<td>2,305</td>
<td>2,100</td>
<td>3,249</td>
</tr>
<tr>
<td>New York</td>
<td>Peak Week</td>
<td>28-Jul-19</td>
<td>39,452</td>
<td>1,452</td>
<td>1,309</td>
<td>42,213</td>
<td>32,382</td>
<td>6</td>
<td>1,512</td>
<td>2,620</td>
<td>3,445</td>
<td>2,260</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>15-Sep-19</td>
<td>39,452</td>
<td>1,452</td>
<td>1,309</td>
<td>42,213</td>
<td>31,244</td>
<td>6</td>
<td>3,377</td>
<td>2,620</td>
<td>3,295</td>
<td>1,683</td>
</tr>
<tr>
<td></td>
<td>NPCC Peak Week</td>
<td>28-Jul-19</td>
<td>39,452</td>
<td>1,452</td>
<td>1,309</td>
<td>42,213</td>
<td>32,382</td>
<td>6</td>
<td>1,512</td>
<td>2,620</td>
<td>3,445</td>
<td>2,260</td>
</tr>
<tr>
<td>Ontario</td>
<td>Peak Week</td>
<td>30-Jun-19</td>
<td>38,271</td>
<td>0</td>
<td>790</td>
<td>39,061</td>
<td>22,105</td>
<td>0</td>
<td>10,767</td>
<td>1,401</td>
<td>1,901</td>
<td>2,887</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>23-Jun-19</td>
<td>36,932</td>
<td>0</td>
<td>791</td>
<td>37,723</td>
<td>21,623</td>
<td>0</td>
<td>11,400</td>
<td>1,667</td>
<td>1,604</td>
<td>1,429</td>
</tr>
<tr>
<td></td>
<td>NPCC Peak Week</td>
<td>28-Jul-19</td>
<td>38,271</td>
<td>0</td>
<td>790</td>
<td>39,061</td>
<td>21,885</td>
<td>0</td>
<td>10,601</td>
<td>1,401</td>
<td>2,029</td>
<td>3,145</td>
</tr>
<tr>
<td>Québec</td>
<td>Peak Week</td>
<td>11-Aug-19</td>
<td>46,677</td>
<td>-1,663</td>
<td>0</td>
<td>45,014</td>
<td>21,005</td>
<td>0</td>
<td>11,880</td>
<td>1,500</td>
<td>1,200</td>
<td>9,429</td>
</tr>
<tr>
<td></td>
<td>Lowest Net Margin</td>
<td>5-May-19</td>
<td>46,677</td>
<td>-1,195</td>
<td>0</td>
<td>45,482</td>
<td>22,047</td>
<td>0</td>
<td>14,915</td>
<td>1,500</td>
<td>1,200</td>
<td>5,820</td>
</tr>
<tr>
<td></td>
<td>NPCC Peak Week</td>
<td>28-Jul-19</td>
<td>46,677</td>
<td>-1,663</td>
<td>0</td>
<td>45,014</td>
<td>20,762</td>
<td>0</td>
<td>12,141</td>
<td>1,500</td>
<td>1,200</td>
<td>9,411</td>
</tr>
</tbody>
</table>
**Generation Resource Changes**

Table 4-10 lists the recent and anticipated generation resource additions, changes and retirements.

### Table 4-10: Resource Changes from Summer 2018 through Summer 2019

<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><strong>Maritimes</strong></td>
<td>Charlottetown Unit #7</td>
<td>-5</td>
<td>Oil</td>
<td>Q1 – 2019</td>
</tr>
<tr>
<td><strong>Net Change</strong></td>
<td>-5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>New England</strong></td>
<td>Southern Sky Renewable Energy RI (Lippitt)</td>
<td>16.3</td>
<td>Solar</td>
<td>Q1 – 2019</td>
</tr>
<tr>
<td></td>
<td>Medway Peaker - SEMARI</td>
<td>207.7</td>
<td>Dual Fuel</td>
<td>Q2 – 2019</td>
</tr>
<tr>
<td></td>
<td>Hope Farm</td>
<td>10</td>
<td>Solar</td>
<td>Q2 – 2019</td>
</tr>
<tr>
<td></td>
<td>Canal 3</td>
<td>333</td>
<td>Dual Fuel</td>
<td>Q2 – 2019</td>
</tr>
<tr>
<td></td>
<td>Southern Sky Renewable Energy RI (Alton)</td>
<td>13.9</td>
<td>Solar</td>
<td>Q2 – 2019</td>
</tr>
<tr>
<td></td>
<td>PSEG Bridgeport Harbor CCGT Expansion</td>
<td>509.6</td>
<td>Dual Fuel</td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td></td>
<td>Constitution Solar</td>
<td>20</td>
<td>Solar</td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td></td>
<td>DWW Solar II, LLC (dba Simsbury Solar Farm)</td>
<td>26.4</td>
<td>Solar</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td></td>
<td>Berkshire Wind Increase</td>
<td>19.8</td>
<td>Wind</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td></td>
<td>Antrim Wind Project</td>
<td>28.4</td>
<td>Wind</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td><strong>Total Addition</strong></td>
<td>1,185</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pilgrim Retirement</strong></td>
<td>-680</td>
<td></td>
<td></td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td><strong>Seasonal Adjustments</strong></td>
<td>63</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Net Change</strong></td>
<td>568</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Area</td>
<td>Generation Facility</td>
<td>Nameplate Capacity (MW)</td>
<td>Fuel Type</td>
<td>In Service Date</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------------------------</td>
<td>-------------------------</td>
<td>-----------</td>
<td>-----------------</td>
</tr>
<tr>
<td>New York</td>
<td>Copenhagen Wind</td>
<td>+80</td>
<td>Wind</td>
<td>Q4 - 2018</td>
</tr>
<tr>
<td></td>
<td>Arkwright Summit</td>
<td>+78</td>
<td>Wind</td>
<td>Q4 - 2018</td>
</tr>
<tr>
<td></td>
<td>Cayuga 2 (IIFO)</td>
<td>-167</td>
<td>Coal</td>
<td>Q3 - 2018</td>
</tr>
<tr>
<td></td>
<td>Selkirk 1 &amp; 2 (retirement rescinded)</td>
<td>+446</td>
<td>Dual</td>
<td>Q4 - 2018</td>
</tr>
<tr>
<td></td>
<td><strong>Total Additions</strong></td>
<td><strong>+158</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Total Subtractions</strong></td>
<td><strong>-167</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Rescinded Retirements</strong></td>
<td><strong>+446</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Net ICAP Adjustments</strong></td>
<td><strong>-310</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Net Change</strong></td>
<td><strong>+127</strong></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>Amherst Island Wind</td>
<td>75</td>
<td>Wind</td>
<td>Q3-2018</td>
</tr>
<tr>
<td></td>
<td>Nanticoke Solar</td>
<td>44</td>
<td>Solar</td>
<td>Q1-2019</td>
</tr>
<tr>
<td></td>
<td>Yellow Falls</td>
<td>16.4</td>
<td>Hydro</td>
<td>Q1-2019</td>
</tr>
<tr>
<td></td>
<td>Loyalist Solar</td>
<td>54</td>
<td>Solar</td>
<td>Q2-2019</td>
</tr>
<tr>
<td></td>
<td>Whitby Cogeneration</td>
<td>-56</td>
<td>Gas</td>
<td>Q2-2019</td>
</tr>
<tr>
<td></td>
<td>Napanee Generating Station</td>
<td>985</td>
<td>Gas</td>
<td>Q2-2019</td>
</tr>
<tr>
<td></td>
<td>Henvey Inlet Wind Farm</td>
<td>300</td>
<td>Wind</td>
<td>Q2-2019</td>
</tr>
<tr>
<td></td>
<td><strong>Seasonal Adjustments</strong></td>
<td><strong>-</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Total Reductions</strong></td>
<td><strong>-56</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Total Additions</strong></td>
<td><strong>1,474</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Net Change</strong></td>
<td><strong>1,418</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td>Small Biomass</td>
<td>38</td>
<td>Biomass</td>
<td>Q2-2019</td>
</tr>
<tr>
<td></td>
<td><strong>Total Retirement</strong></td>
<td><strong>0</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Total Addition</strong></td>
<td><strong>38</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Seasonal Adjustments</strong></td>
<td><strong>-8</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Net Change</strong></td>
<td><strong>+30</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Maritimes

Since the 2018 Summer Operating Period, there has been a net decrease of 5 MW of installed capacity in the Maritimes.

New England

Since the 2018 Summer Operating Period, New England has three significant new generation projects, all of which have a primary fuel source of natural gas and are dual-fuel capable, which are expected to be in service for the 2019 summer peak. The first is the West Medway Jet 4 and 5, providing approximately 208 MW total. The second is Canal 3, capable of providing approximately 333 MW. The third is the Bridgeport Harbor 5 Combined-Cycle facility, with 510 MW of new capacity. New solar projects totaling 86.5 MW of nameplate capacity have been added in New England, along with 48 MW of new wind projects.

The seasonal adjustments value of 63 MW is a result of seasonal claimed capability audits and other performance factors.

New York

Since the 2018 Summer Operating Period, three noteworthy changes to generation in New York have occurred. Two nameplate capacity additions are expected to be in-service for the summer peak. These are the Copenhagen Wind plant (+79.9 MW) and the Arkwright Summit wind project (+78 MW). In addition to these changes, 446 MW of nameplate generation that had previously submitted notices of intent to retire have rescinded those notices.

Ontario

By the end of the 2019 Summer Operating Period, a number of new solar, hydro, wind and gas generators are expected to be in-service. The biggest of these are the Nanpanee Generating Station (985 MW) and the Henvey Inlet Wind Farm (300 MW). From a capacity reduction perspective, one contract for a natural gas facility will expired in Q2-2019 reducing the effective capacity by 56 MW. The total Ontario installed capacity is expected to increase to 38,271 MW by the end of the Summer 2019 assessment period. This is an increase of approximately 1,400 MW from the end of last year’s summer assessment period.
Québec

For the upcoming Summer Operating Period, biomass generation is expected to increase by 38 MW. -8 MW of seasonal adjustments have been made, bringing the Installed Capacity to a total of 46,677 MW; a net 30 MW increase since the last summer assessment.
Fuel Infrastructure by Reliability Coordinator Area

Figure 4-1 and Figure 4-2 depict installed generation resource profiles for each Reliability Coordinator area and for the NPCC Region by fuel supply infrastructure as projected for the NPCC coincident peak week.

Figure 4-1: Resource Fuel Type by Reliability Coordinator Area

- Maritimes:
  - 17% Hydro/Tidal
  - 10% Nuclear
  - 14% Gas
  - 4% Oil
  - 8% Coal
  - 7% Wind
  - 8% Other
- New England:
  - 4% Solar
  - 3% Other
  - 2% Gas
  - 3% Oil
  - 6% Coal
  - 2% Wind
  - 5% Nuclear
  - 14% Coal
  - 10% Oil
- New York:
  - 14% Solar
  - 5% Other
  - 2% Gas
  - 10% Oil
  - 24% Coal
  - 2% Wind
  - 22% Nuclear
  - 34% Coal
- Ontario:
  - 8% Solar
  - 5% Other
  - 2% Gas
  - 5% Oil
  - 22% Coal
  - 34% Nuclear
  - 13% Hydro/Tidal
- Québec:
  - 8% Solar
  - 5% Other
  - 2% Gas
  - 5% Oil
  - 22% Coal
  - 34% Nuclear
  - 13% Hydro/Tidal
Figure 4-2: Resource Fuel Type for NPCC
**Wind and Solar Capacity Analysis by Reliability Coordinator Area**

For the upcoming 2019 Summer Operating Period, installed wind and solar capacity accounts for approximately 9.14% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 8.03% wind and 1.11% solar. This is an increase from 7.46% reported in 2018 (7.00% and 0.46% respectively). Reliability Coordinators have distinct methods of accounting for both of these types of generation. The Reliability Coordinators continue to develop their knowledge regarding the operation of wind and solar generation in terms of capacity forecasting and utilization factor. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII, page 46-48.

Table 4-11 below illustrates the nameplate wind capacity in NPCC for the 2019 Summer Operating Period. The Maritimes, IESO, NYISO 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. ISO-NE reduces the nameplate capacity and includes this reduced capacity value directly in the Installed Capacity section of the Load and Capacity Table. Please refer to Appendix II, for information on the derating methodology used by each of the NPCC Reliability Coordinators.

Table 4-11 below also illustrates the nameplate solar capacity in NPCC for the 2019 Summer Operating Period. The IESO and NYISO 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. ISO-NE reduces the nameplate capacity and includes this reduced capacity value directly into the Installed Capacity section of the Load and Capacity Table. Please refer to Appendix II for information on the derating methodology used by each of the NPCC Reliability Coordinators.

Table 4-12 illustrates behind-the-meter solar PV capacity and the amount of impact it has on peak load demand for each area. The IESO, ISO-NE and NYISO each factor in behind-the-meter solar as a peak load reduction. Methodologies for each area can be found in Appendix IV.
Table 4-11: NPCC Wind and Metered Solar Capacity

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>1,152</td>
<td>319</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>New England</td>
<td>1,420</td>
<td>192</td>
<td>1,299</td>
<td>449</td>
</tr>
<tr>
<td>*New York</td>
<td>1,985</td>
<td>324</td>
<td>57</td>
<td>16</td>
</tr>
<tr>
<td>Ontario</td>
<td>4,786</td>
<td>651</td>
<td>478</td>
<td>48</td>
</tr>
<tr>
<td>Québec</td>
<td>3,880</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>13,223</td>
<td>1,486</td>
<td>1,834</td>
<td>513</td>
</tr>
</tbody>
</table>

*Total nameplate wind capacity in New York is 1,985 MW, however only 1,739 MW participates in the ICAP market as of this writing. Total nameplate grid connected solar capacity is 57 MW while only 32 MW participates in the ICAP market as of this writing.

Table 4-12: Behind-the-Meter Solar PV

<table>
<thead>
<tr>
<th>Area</th>
<th>Installed Behind-the-Meter Solar PV (MW)</th>
<th>Impact of BTM Solar PV on Peak Load (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>New England</td>
<td>2,048</td>
<td>708</td>
</tr>
<tr>
<td>New York</td>
<td>1,862</td>
<td>542</td>
</tr>
<tr>
<td>Ontario</td>
<td>2,264</td>
<td>229</td>
</tr>
<tr>
<td>Québec</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>6,174</td>
<td>1,479</td>
</tr>
</tbody>
</table>

Maritimes

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

The Northern Maine Independent System Administrator (NMISA) uses a fixed capacity factor of 30% for both the summer and winter assessment periods.

Nova Scotia applies a 18% capacity value to installed wind capacity (82% derated). This figure was calculated via a Cumulative Frequency Analysis of historical wind data (2010-2015). 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 18% of installed wind capacity online and generating in 90% of peak hours.
New England

During the 2019 summer assessment period, ISO-NE has over 1,400 MW of wind resources interconnected to the grid and has derated these wind resources by nearly 90% as a result of established summer Claimed Capability Audits (CCAs).

Sustained growth in distributed PV has been observed over the last several years and is anticipated to continue over the long-term. By the end of 2018, 2,884 MW (1,788 behind-the-meter and 1,096 in-front-of-the-meter) of nameplate PV was installed within the region, and additional PV is forecasted for the 2019 summer assessment period. This is in-line with the 2018 PV forecast and New England expects this increase in PV will continue to impact future net demand forecasting. Planning considers the 1,299 MW of in-front-of-the-meter PV, consisting of those resources with an FCM obligation and considered Settlement-Only generation (SOG). Of which, less than 100 MW is telemetered and dispatchable by Real-time Operations.

Based on ISO-NE’s analysis of PV performance during peak demand conditions, BTM PV is expected to reduce the summer gross peak load by 708 MW or approximately 35% of nameplate capacity. The percentage of nameplate, used by ISO-NE to estimate the peak demand reduction, are meant to reflect realistic performance of PV during summer peak demand conditions, as well as diminishing PV production as increasing PV penetrations shift the timing of the summer peak later in the day. Therefore, this percentage of nameplate becomes lower as PV penetrations increase. The estimated peak demand reduction value also includes a gross-up of 8% to reflect avoided transmission and distribution losses. As state policies evolve in their support of renewable energy development, ISO-NE continues to monitor PV growth and improve its forecast methodologies within the six-state region. The BTM PV factor continues to affect the load forecasting process, as further discussed in Section 6.
New York

For the 2019 Summer Operating Period, the NYISO anticipates 8,767 MW of nameplate renewable resource capacity to be available. This includes 1,985 MW of nameplate wind and 57 MW of nameplate grid-connected solar capacity. As indicated above, 1,739 MW of nameplate wind and 32 MW of nameplate grid connected solar capacity participate in the New York ICAP (Installed Capacity) market as of this writing. Non-ICAP capacity is not included in the Installed Capacity of Tables 4-5 and AP-4. The ICAP nameplate capacity is counted at full value towards the Installed Capacity for New York. The wind and solar capacities are derated by 83% and 50% respectively based on historical performance data when determining operating margins.

In 2018, 4,034 gigawatt-hours of New York’s energy was produced by wind and solar resources representing approximately 2.98% of New York’s electric generation.

Behind-the-meter solar photovoltaic resources are expected to have a significant impact on peak loads in New York. It is estimated that there are 1,862 MW of installed behind-the-meter solar PV which is forecasted to reduce coincident peak load by 542 MW. This impact is reflected in New York’s 32,382 MW peak load forecast. Additionally, behind-the-meter solar PV energy is expected to be 2,161 GWh in 2019. It is also estimated that installed behind-the-meter solar PV is increasing by about 15 MW per month. Details of the methodology used to determine the impact of solar PV on peak load can be found in Appendix IV.

Ontario

For Ontario, monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values in percentage of installed capacity are determined from actual historic median wind generator contribution over the last 10 years at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. For the month of July when the peak loading is anticipated to occur, the monthly Wind Capacity Contribution factor is expected to be 13.6%.

Similarly, monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the median contribution during the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process
of combining historical solar data and the simulated 10-year historical solar data will be incorporated into the SCC methodology, until sufficient actual solar production history has been accumulated, at which point the use of simulated data will be discontinued. For the month of July when the peak loading is anticipated to occur, the SCC factor is 10.1%.

From an adequacy assessment perspective, although the entire installed capacity of the wind and solar generation is included in Ontario’s total installed capacity number, the appropriate reduction is applied to the ‘Known Maint./Derate/Bottled Cap.’ number to ensure the WCC and SCC values are accounted for when assessing net margins.

Embedded (behind-the-meter) generation reduces the need to grid supplied electricity by generating electricity on the distribution system. Since the majority of embedded generation is solar powered, embedded generation is divided into two separate components – solar and non-solar. Non-solar, embedded generation includes generation fuelled by biogas and natural gas, water and wind. Contract information is used to estimate both the historical and future output of embedded generation. This information is incorporated into the demand forecast model. The growth in embedded generation capacity, a major offset to demand, has plateaued, but continues to be a significant driver of change in the sector.

There was 2,228 MW of installed behind the meter solar PV in the summer of 2018 which increased to 2,264 MW by the summer of 2019. It should be noted that due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed later in the day. As a consequence, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

Québec

In the Québec Area, wind generation plants are owned and operated by Independent Power Producers (IPPs). No wind generation addition is expected prior to the 2019 summer peak period. During the summer period, 100% of the wind installed capacity is derated. Solar generation in the Québec Area is negligible.
Demand Response Programs

Each Reliability Coordinator area utilizes various methods of demand management. Grid modernization, smart grid technologies, and their resulting market initiatives have created a need to treat some demand response programs as supply-side resources, rather than as a load-modifier. The table below summarizes the expected Dispatchable Demand-Side Management (DDSM) Resources and Interruptible Loads available within the NPCC region for the forecasted peak demand week of July 28, 2019. Definitions of the terms are included in Appendix II. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII, page 48.

Table 4-13: Summary of Active Demand Response Programs

<table>
<thead>
<tr>
<th>Area</th>
<th>DDSM Resources (MW)</th>
<th>Interruptible Loads (MW)</th>
<th>Total (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>0</td>
<td>369</td>
<td>369</td>
</tr>
<tr>
<td>New England</td>
<td>340</td>
<td>0</td>
<td>340</td>
</tr>
<tr>
<td>New York</td>
<td>1,309</td>
<td>6</td>
<td>1,315</td>
</tr>
<tr>
<td>Ontario</td>
<td>790</td>
<td>0</td>
<td>790</td>
</tr>
<tr>
<td>Québec</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,439</strong></td>
<td><strong>375</strong></td>
<td><strong>2,814</strong></td>
</tr>
</tbody>
</table>

**Maritimes**

Interruptible loads are forecast on a weekly basis and range between 276 MW and 369 MW. The values can be found in Table AP-2 and are available for use when corrective action is required within the Area.

**New England**

ISO-NE Demand Response Capacity Resources (DRCRs) can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO, participate in the Day-Ahead and Real-Time Energy Markets and are counted as supply-side capacity.
New York

The NYISO has three demand response programs to support system reliability. The NYISO currently projects 1,315 MW of total demand response available for the 2019 summer season, consisting of approximately 1,309 MW of Special Case Resources and 6 MW of Emergency Demand Response Program resources.

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 Targeted Demand Response Program (“TDRP”), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a Transmission Owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City.
Ontario

Ontario’s demand response is comprised of the following programs: Dispatchable Loads and resources procured through the Demand Response (DR) auction. Demand measures are dispatched like a generation resource and therefore are included in the supply mix. Load modifiers include energy efficiency (energy-efficiency programs, codes and standards), price impacts (time of use and Industrial Conservation Initiative) and embedded generation. The load modifiers are incorporated into the demand forecast.

For the summer assessment period, the capacity of the demand response program consists of 737 MW of DR auction participants with the balance of 53 MW being made up by dispatchable loads.

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 transfer capabilities between the Reliability Coordinator Areas of NPCC under normal and peak demand configurations.

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. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII, page 18.

### Inter-Regional Transmission Adequacy

#### Ontario – Manitoba Interconnection

The Ontario – Manitoba interconnection consists of two 230 kV circuits and one 115kV circuit. The transfers on the 230 kV are constrained by stability and thermal limitations; 225 MW for exports and 293 MW 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 with a total transfer capability export limit of 1,700 MW and an import limit of 1,700 MW which are all constrained by thermal limitations. There are four phase angle regulators in service to help manage flows on the interface.

#### New York – PJM Interconnection

The New York – PJM interconnection consists of one PAR controlled 500/345 kV circuit, one uni-directional DC cable into New York, one uni-directional DC/DC controlled 345 kV circuit into New York, two free flowing 345 kV circuits, a VFT controlled 345/230 kV circuit, five PAR controlled 345/230 kV circuits, two free flowing 230 kV circuits, three 115 kV circuits, and a 138/69 kV network serving a PJM load pocket through the New York system.
The Hudson-Farragut and Marion-Farragut PAR controlled 230/345 kV circuits (B3402 & C3403) will remain out of service for the duration of the 2019 summer period.

**Inter-Area Transmission Adequacy**

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

The table below, Table 5-1, summarizes the transfer capabilities between each region. Full details can be found in Appendix III.

<table>
<thead>
<tr>
<th>Area</th>
<th>Total Transfer Capability (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transfers from Maritimes to</td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td>735</td>
</tr>
<tr>
<td>New England</td>
<td>1,000</td>
</tr>
<tr>
<td>Transfers from New England to</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>1,370</td>
</tr>
<tr>
<td>Transfers from New York to</td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>2,130</td>
</tr>
<tr>
<td>Ontario</td>
<td>1,700</td>
</tr>
<tr>
<td>PJM</td>
<td>1,665</td>
</tr>
<tr>
<td>Québec</td>
<td>1,040</td>
</tr>
<tr>
<td>Transfer from Ontario to</td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>1,950</td>
</tr>
<tr>
<td>Québec</td>
<td>2,135</td>
</tr>
</tbody>
</table>
### Area Total Transfer Capability (MW)

<table>
<thead>
<tr>
<th>Area</th>
<th>Total Transfer Capability (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transfers from Québec to</td>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
<td>741 + radial load</td>
</tr>
<tr>
<td>New England</td>
<td>2,275</td>
</tr>
<tr>
<td>New York</td>
<td>1,990</td>
</tr>
<tr>
<td>Ontario</td>
<td>2,800</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 2019 Operating Period and have provided the following review as well as identified transmission improvements listed in Table 5-2.

**Table 5-2: 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>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>New England</td>
<td>Coopers Mill STATCOM</td>
<td>345</td>
<td>Q2 - 2018 (Completed)</td>
</tr>
<tr>
<td></td>
<td>Ascutney SVC</td>
<td>115</td>
<td>Q4 - 2018 (Completed)</td>
</tr>
<tr>
<td></td>
<td>Farmwood Synchronous Condenser</td>
<td>115</td>
<td>Q4 - 2018 (Completed)</td>
</tr>
<tr>
<td>New York</td>
<td>South Perry (new station btw. Meyer and Wethersfield)</td>
<td>230</td>
<td>Q3 - 2018 (Completed)</td>
</tr>
<tr>
<td></td>
<td>Cricket Valley substation (btw. Pleasant Valley and Long Mt.)</td>
<td>345</td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td></td>
<td>Rainey-Corona PAR</td>
<td>345/138</td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td>NPCC Sub-Area</td>
<td>Transmission Project</td>
<td>Voltage (kV)</td>
<td>In Service</td>
</tr>
<tr>
<td>---------------</td>
<td>----------------------------------------------------------</td>
<td>--------------</td>
<td>-------------------</td>
</tr>
<tr>
<td></td>
<td>Erie East-South Ripley 69 (new series reactor)</td>
<td>230</td>
<td>Q2 – 2019 (Completed)</td>
</tr>
<tr>
<td></td>
<td>E. 13 St. reconfig. (ongoing)</td>
<td>345</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td>Ontario</td>
<td>Copeland MTS: Line Connection</td>
<td>230</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td></td>
<td>Terry Fox MTS: Build New 230kV Line Tap</td>
<td>230</td>
<td>Q1 - 2019</td>
</tr>
<tr>
<td></td>
<td>Niagara Region Reinforcement (Q26M, Q35M)</td>
<td>230</td>
<td>Q2 - 2019</td>
</tr>
<tr>
<td></td>
<td>Chenaux TS refurbish 115kV switchyard</td>
<td>115</td>
<td>Q3 - 2019</td>
</tr>
<tr>
<td></td>
<td>Kapuskasing Area Reinforcement (H9K)</td>
<td>230</td>
<td>Q4 - 2019</td>
</tr>
<tr>
<td>Québec</td>
<td>Line between Chamouchouane and Duvernay substations</td>
<td>735</td>
<td>Q2 - 2019</td>
</tr>
</tbody>
</table>

**Maritimes**

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Summer Operating Period. Part of the Total Transfer Capability (TTC) calculation with HQ is based on the ability to transfer radial loads onto the HQ system. The radial load value is calculated monthly and HQ will be notified of the changes (see Appendix III).

A 500 MW (475 MW received in Nova Scotia) High Voltage Direct Current (HVDC) undersea cable link (Maritime Link) between Newfoundland, Labrador and Nova Scotia was installed in late 2017; however, the 153 MW firm capacity contract from the Muskrat Falls hydro development in Labrador is not expected until late-2020. The firm capacity contract is expected to facilitate the retirement of a 153 MW coal-fired unit in Nova Scotia by late-2020, thus the overall resource adequacy will be unaffected by these changes. Currently the Maritime Link is being used as an additional tie line providing minimal energy flow between Nova Scotia and Newfoundland.

**New England**

The existing New England transmission system is projected to be sufficient for the 2019 Summer Operating Period. Numerous transmission upgrades continue to be commissioned to address New England’s reliability needs. These transmission improvements have reinforced the overall reliability of the electric power system and
reduced congestion, enabling power to flow more easily around the entire region. The improvements support decreased energy costs and increased power system flexibility.

The Coopers Mills STATCOM (static synchronous condenser) is a component of the Greater Boston Reliability Project. This project identified transmission reinforcements required in the Boston area to reliably continue to serve the area’s increasing load. The Coopers Mills STATCOM is connected to Central Maine Power Company’s (CMP) Coopers Mills 345 kV substation in Maine. The STATCOM is rated at −200 / + 200 MVar. The completion of the Coopers Mills STATCOM will enable an increase in interface transfer capability.

The Ascutney SVC (static VAR [voltage ampere reactive] compensator) is rated at −25/+50 MVAr and is interconnected to the Ascutney 115 kV bus in Vermont. It will improve local southern Vermont voltage support for local area load support.

The Farmwood synchronous condensers are two −13/+25 MVAr units (total −26 / +50 MVAr) interconnected to the Farmwood 115 kV bus in central New Hampshire. They will improve local central New Hampshire voltage support for local area load support.

**New York**

For the 2019 Summer Operating Period, New York does not anticipate any reliability issues for operating the bulk power system. Notable changes to the transmission system include the new Cricket Valley substation and the ONT-NY L33 PAR outage.

The new Cricket Valley substation is on the Pleasant Valley-Long Mountain 398 345 kV line on the New York side of the New York-New England interface. It is expected to be in service in June 2019 and will facilitate interconnection of the new Cricket Valley combined cycle generating station.

The L33 230 kV PAR, between Ontario and New York, suffered a catastrophic failure in April of 2018 and is not expected to return to service until 2021.

The Hudson-Farragut and Marion-Farragut PAR controlled 230/345 kV (B3402 & C3403) circuits will remain out of service for the duration of the 2019 summer period.

**Ontario**

For the Summer 2019 Operating Period, Ontario’s transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmissions outages. Ontario has an expected coincident import capability of approximately 5,200 MW.
Outages affecting neighboring jurisdictions can be found in Table 5-3: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the Summer 2019 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. During the 2019 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.

In recent years, planning studies have shown the need to reinforce the transmission system with a new 735-kV line in order to meet the reliability standards. The line (about 400 km or 250 miles) will extend from the Chamouchouane substation on the eastern James Bay subsystem to Duvernay substation near Montréal. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line was initially scheduled for the 2018–2019 winter peak period but the project has been delayed to 2019. For this purpose, a few 735 kV lines will be taken out of service and these outages will be tightly coordinated to ensure minimum impact on system operations.
**Area Transmission Outage Assessment**

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

**Table 5-3: Area Transmission Outage Assessment**

**Maritimes**

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Outage</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>Point Lepreau GS</td>
<td>2019/04/05</td>
<td>2019/05/05</td>
<td>400 MW Import 650 MW Export</td>
</tr>
</tbody>
</table>

**New England**

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Outage</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York</td>
<td>L398</td>
<td>2019/03/01</td>
<td>2019/05/19</td>
<td>600 MW Import 400 MW Export</td>
</tr>
</tbody>
</table>
### New York

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Outage</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM</td>
<td>Hudson-Farragut &amp; Marion-Farragut (B3402 &amp; C3403)</td>
<td>2018/01/15</td>
<td>2019/12/31</td>
<td>600 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>250 MW Export</td>
</tr>
<tr>
<td>New England</td>
<td>Long Mt.-Pleasant Valley</td>
<td>2019/03/01</td>
<td>2019/05/19</td>
<td>800 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>900 MW Export</td>
</tr>
</tbody>
</table>

### Ontario

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Outage</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td>B31L</td>
<td>2019/06/11</td>
<td>2019/07/04</td>
<td>400 MW Import</td>
</tr>
<tr>
<td>New York</td>
<td>PA302</td>
<td>2019/06/03</td>
<td>2019/06/13</td>
<td>1000 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>950 MW Import</td>
</tr>
<tr>
<td>New York</td>
<td>PA302</td>
<td>2019/07/21</td>
<td>2019/09/03</td>
<td>1000 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>950 MW Import</td>
</tr>
<tr>
<td>New York</td>
<td>PA302</td>
<td>2019/09/04</td>
<td>2019/11/03</td>
<td>1000 MW Export</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>950 MW Import</td>
</tr>
<tr>
<td>MISO</td>
<td>L4D</td>
<td>2019/04/01</td>
<td>2019/05/03</td>
<td>650 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>600 MW Export</td>
</tr>
<tr>
<td>MISO</td>
<td>L51D</td>
<td>2019/05/06</td>
<td>2019/05/31</td>
<td>650 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>600 MW Export</td>
</tr>
</tbody>
</table>
### Québec

<table>
<thead>
<tr>
<th>Impacted Area</th>
<th>Outage</th>
<th>Planned Start</th>
<th>Planned End</th>
<th>Reduction in Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York</td>
<td>TFV Langlois</td>
<td>2019/09/09</td>
<td>2019/09/26</td>
<td>100 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100 MW Export</td>
</tr>
<tr>
<td>New England</td>
<td>L1401 (DER)</td>
<td>2019/08/05</td>
<td>2019/08/15</td>
<td>50 MW Export</td>
</tr>
<tr>
<td>New England</td>
<td>L1429 (HIGH)</td>
<td>2019/06/03</td>
<td>2019/06/06</td>
<td>170 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>225 MW Export</td>
</tr>
<tr>
<td>New York</td>
<td>GC1 Châteauguay (MASS)</td>
<td>2019/04/29</td>
<td>2019/05/24</td>
<td>500 MW Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>500 MW Export</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>GC1 Madawaska (NB)</td>
<td>2019/05/27</td>
<td>2019/06/14</td>
<td>420 Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>420 Export</td>
</tr>
<tr>
<td>Ontario</td>
<td>GC2 Outaouais (ON)</td>
<td>2019/05/05</td>
<td>2019/05/12</td>
<td>625 Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>625 Export</td>
</tr>
<tr>
<td>Ontario</td>
<td>GC2 Outaouais (ON)</td>
<td>2019/05/26</td>
<td>2019/06/02</td>
<td>625 Import</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>625 Import</td>
</tr>
</tbody>
</table>
6. **Operational Readiness for 2019**

**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 (SVC) 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).

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

*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 Management and Control*

ISO-NE manages and monitors both reactive resources and transmission voltages on the bulk power system. These elements are monitored in dedicated EMS reactive power displays, specific voltage/reactive transmission operating guides and via real-time voltage transfer limit evaluation software. ISO-NE also reviews and manages low side Load Power Factor requirements in the region which accounts for the potential impacts of the distribution load on the Bulk Electric System (BES) transmission performance. ISO-NE also maintains a detailed set of generator voltage set points and appropriate operational bandwidths recognizing the lead/lag capabilities of the individual resources, which are monitored in real time within the EMS. In conjunction with the asset owners, ISO-NE has developed a set of comprehensive normal, long-term and short-term voltages limits for the BES transmission system and communicates potential issues or concerns with the Transmission Owners. Based on operational studies and experience, the impact of
available dynamic and static reactive resources is accounted for in outage coordination and real-time operations.

In preparation for the summer and winter operating periods, ISO–NE will perform a voltage reduction test & audit with each Transmission Owner (TO) that has control over transmission/distribution facilities to verify voltage reduction capability. It is intended that voltage reductions be fully implemented within ten minutes from the time ordered. However, it is recognized that it may not be practical for some TOs with control over transmission/distribution facilities to meet this requirement. In those circumstances, voltage reduction which can be implemented in thirty minutes is permissible. ISO-NE and the Local Control Centers (LCCs) use this capability to reduce demand to maintain system reliability. ISO New England Operating Procedure No. 13 (OP-13) Standards for Voltage Reduction and Load Shedding Capability\(^9\), establishes standards for the testing of TOs that have control over transmission/distribution facilities voltage reduction and load shedding capability.

**Solar Integration (PV)**

New England is forecasting a gross normal summer peak of 28,943 MW and a net normal summer peak of 25,323 MW. The net demand forecast takes into account demand reducers such as 2,912 MW of Passive Demand Resources (PDR) and 708 MW of BTM PV. PDR and BTM PV are reconstituted into the historical hourly loads to ensure the proper accounting of PDR and BTM PV, which are both forecast separately. The 2019 BTM PV forecast reflects recent development trends in the region, as indicated by data provided by region’s Distribution Owners, and updated policy information provided by the New England states.

In the day-ahead load-forecast process, forecasters manually adjust hourly loads to account for the effects of BTM PV. Any inaccuracies are corrected by adjusting the combined output of the load-forecast models using an hourly BTM PV forecast, which is derived from an irradiance forecast and PV panel installation information. Because load-forecast models tend to learn the average effects of BTM PV over time, the forecaster must adjust the expected load reduction from the PV forecast to offset what the models have learned. Efforts to improve BTM PV forecasts in the short-term and real-time process are ongoing.

\(^9\) Operating Procedure No. 13 is located on the ISO’s web site at: [https://www.iso-ne.com/rules_proceds/operating/isone/op13/op13_rto_final.pdf](https://www.iso-ne.com/rules_proceds/operating/isone/op13/op13_rto_final.pdf)
Zonal Load Forecasting

In addition to the efforts above, New England continues to produce 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 by taking into account weather differences across the region which may distort the normal distribution of load. An example would be when the Boston zone temperature is forecasted to be sixty-five degrees while the Hartford area is forecasting ninety degrees. This zonal forecast when rolled up provides a better New England demand forecast resulting in a better reliability commitment across the region.

Natural Gas Supply

With natural gas as the predominant fuel source for power generation in New England, the ISO continues to monitor factors impacting the natural gas fuel deliverability for the area. For the 2019 Summer capacity period, the ISO expects limited amounts of natural gas pipeline maintenance and construction to occur for select areas and does not forecast major deliverability issues that would affect the installed capacity.

For the 2019 Summer Assessment, ISO-NE has several operating procedures that can be invoked to help mitigate energy 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.10

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 energy deficiency, unacceptable voltage levels, or any other emergency that ISO-NE deems appropriate in an isolated or widespread area of New England.11

10 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

11 Operating Procedure No. 7 is located on the ISO’s web site at: http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf
3. ISO-NE’s Operating Procedure No. 21 - *Energy Inventory Accounting and Actions 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\(^{12}\). 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 Operator (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 2019.

The weather-normalized 2018 peak was 32,512 MW, 392 MW (1.2%) lower than the forecast of 32,904 MW. The current 2019 peak forecast is 32,382 MW. It is lower than the 2018 forecast by 522 MW (1.6%). The forecast based on extreme weather conditions, set to the 90th percentile of typical peak-producing weather conditions for 2019 is 34,186 MW. The lower forecasted growth in energy usage can largely be attributed to the projected impact of existing statewide energy efficiency initiatives and the growth of distributed behind-the-meter energy resources encouraged by New York State energy policy programs such as the Clean Energy Fund (CEF), the NY-SUN Initiative, and other programs developed as part of the Reforming the Energy Vision (REV) proceedings.

The peak load forecast was reduced by 228 MW for energy efficiency impacts, 542 MW for behind-the-meter PV impacts, 224 MW for other distributed generation impacts, and 7 MW for behind-the-meter energy storage. Projected electric vehicle usage increased the peak load forecast by 24 MW.

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

\(^{12}\) Operating Procedure No. 21 is located on the ISO’s web site at: [http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdf](http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdf)
resolved. During the 2019 summer season, New York expects to have 1,452 MW of net import capacity available based on current external purchases and sales.

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. SCRs 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 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 is required to keep these peaking units operating to avoid the loss of load. Under this agreement (DEC, Declaratory Order # 19-12) if the NYISO issues 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.
Energy Storage

Energy storage units are split between transmission system, distribution system, and customer-sited storage. Customer-sited units are considered behind-the-meter, while transmission system and distribution system units are assumed to be part of the wholesale market. Both wholesale and behind-the-meter energy storage units will have relatively small positive net annual electricity consumption due to battery charging and discharging cycles. Only behind-the-meter energy storage units will reduce peak loads when injecting into the grid, and only a portion of installed units are expected to be injecting during the NYCA summer and winter peak hours. Wholesale market energy storage does not reduce peak load because it is assumed to be dispatched as generation. Total energy storage nameplate capacity is projected to be 44 MW including both wholesale and behind-the-meter capacity.

Ontario

Base Load

Ontario will continue to experience potential Surplus Baseload Generation (SBG) over the outlook period. However, the magnitude and the frequency of the SBG are reduced with nuclear refurbishment process in flight since 2016. It is expected that the SBG will continue to be managed effectively through existing market mechanisms, which includes intertie scheduling, the dispatch of grid-connected renewable resources and nuclear maneuvers or shutdown.

Embedded solar and wind 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)

Operating Flexibility

The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation and expected and actual Ontario demand continues to be a priority. To assist in addressing flexibility needs, the IESO will continue to enact the newly introduced (summer 2018) procedure to schedule additional 30-minute operating reserve as required throughout the 2019 summer period.

Outage Management

As a result of significant differences between normal and extreme weather forecasts in the summer and several enhancements to IESO’s resource modelling, the IESO has greater visibility of generation availability and reserves above requirement in extreme weather
conditions. Therefore, the IESO is moving towards approving outages using extreme
weather (with up to 2000 MW of imports) instead of normal weather conditions.

The new outage approval criterion will allow more planned outages in the winter or
shoulder months when there is more room for outages. IESO plans to begin using this
criterion to assess requests that extend past of begin after May 1, 2019. Previously, the
IESO used the normal weather forecast under the firm resource scenario plus up to 700
MW of imports to assess outages.

Voltage Control

Ontario does not foresee any voltage management issues this summer season. However,
as high voltage situations arise during periods of light load, the removal of at least one
500 kV circuit may be required to help reduce voltages. Planning procedures are in place
to ensure adequate voltage control devices are available during outage conditions when
voltage control conditions are more acute. To address high voltage issues on a more
permanent basis, the IESO has requested additional high voltage reactors at Lennox TS
with a target in-service date of Q4 - 2020.

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.
Because summers are generally getting warmer, the air conditioning load is increasing year after year and transfers to summer peaking systems are increasing. Studies have been performed and thermal limits continue to be optimized to ensure that no line becomes overloaded following a contingency in hot temperature periods.
Summer 2019 Solar Terrestrial Dispatch Forecast of Geomagnetically Induced Current

Solar Activity Forecast Discussion

For the 2019 Summer Operating Period, solar activity will continue to remain at quiet levels. The solar coronal regions are stabilizing as the next solar minimum approaches, with fewer coronal holes and fewer extensions to lower solar latitudes that can sweep higher velocity solar winds toward the Earth. The number of days in which the Earth is engulfed in a higher velocity coronal hole solar wind stream also reduces during this phase of the solar cycle and in general, geomagnetic activity tends to be less active. There are also far fewer coronal mass ejections during this phase of the solar cycle, and those which are observed are typically benign and slower moving.

It should be noted that during the solar minimum years of many prior solar cycles (including the last solar cycle), there have been brief intervals of approximately two weeks in duration where a large and complex sunspot group unexpectedly forms that unleashes strong levels of solar activity. These sunspot complexes usually don’t last long, but have historically generated substantial solar flare events - even deep into the X-class flaring category - and dangerous coronal mass ejections that sharply contrast with the usually quiet levels of solar activity seen during solar minimum conditions. The occurrence, significance, and magnitude of sunspot formations are difficult to predict. It is important that Power System Operators understand that these rogue events can and do occur. The odds of such an event during any particular week of the coming summer are very low. Operators should at least be aware that the risk of such events exists and should be taken seriously, as their impacts have the potential to be as powerful as events that happen during the solar maximum years.

Generally, there is expected to be only one recurrent coronal hole-based disturbance each month during the upcoming summer. Commencing in April, the disturbance is likely to occur near the latter part of the month and result in levels of geomagnetic activity that may reach minor storm conditions (K-indices of 5). Such activity is capable of generating GIC activity, but generally is not as capable of producing strong GIC activity. The same disturbance then rotates with the Sun and returns back to sweep past the Earth again at similar strength levels around the following dates: May 20, June 16, July 13, August 9, September 5 and October 2.

Expect geomagnetic K-indices during each of these events to peak at values near 4 or 5 (with smaller risks for brief major storming at K-indices of 6), but with most of the activity
dominantly occurring at K-index levels of 3 to 4. The duration of each of these periods of enhanced activity should be on the order of a few days, with the first 24 hours being the most volatile in terms of possible GIC activity. There are currently no sunspot groups capable of producing any significant solar disturbances, and there are likely to be very few (if any) that form this summer - except as cautioned above. Most of the enhanced geomagnetic activity expected is forecasted to be from stable coronal holes or extensions of the solar polar coronal holes. These features tend to change shape and location slowly over time, therefore being one of the few features of the Sun that can be relatively accurately predicted into the future.
7. Post-Seasonal Assessment and Historical Review

Summer 2018 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator Area’s Summer 2018 operational experiences.

The NPCC coincident peak was 103,231 MW and occurred on June August 28, 2018 at HE18 EDT.

Maritimes

The Maritimes peak demand during the NPCC coincident peak was 3,134 MW. Maritimes actual peak was 3,243 MW on August 28, 2018 at HE16 EDT.

All major transmission lines were in service.

New England

The New England peak demand during the 2018 NPCC coincident peak was 25,386 MW. The New England peak demand value of 25,899 MW was observed on August 29, 2018 HE17 EDT.

The forecasted normal peak demand for 2018 summer was 26,482 MW.

Capacity Scarcity Condition – Monday, September 3, 2018

• Two primary factors led to the implementation of an OP 4 event:
  – Significant generation outages and reductions totaling ~1650 MW occurred during the dispatch day
  – Higher than forecasted temperatures and dew points with largest departures in the afternoon resulted in significant load forecast deviations

• 30-minute Reserve Constraint Penalty Factor violated for the following 5-minute intervals: 15:40 – 18:15
  – $1,000/MWh Reserve Constraint Penalty Factor

• 10-minute Reserve Constraint Penalty Factor violated for the following 5-minute intervals: 17:00 – 17:10 and 17:35 – 18:00
  – $1,500/MWh Reserve Constraint Penalty Factor

• System conditions required implementation of M/LCC 2 and OP 4
  – M/LCC 2: 15:15 – 21:00
  – OP 4, Actions 1,2: 15:30 – 20:00
  – OP 4, Actions 3-5: 16:00 – 21:00
• Prior to the significant outage of a resource between 15:00 and 15:30, the ISO committed ~600 MW of capacity resources

• Subsequent to the large outage, the ISO committed all remaining resources totaling ~45 MWs with short enough notification and start times that they could assist in meeting the evening peak

Additional details can be found in Appendix VIII – page 30.

**New York**

The peak demand of 31,861 MW occurred August 29, HE17 EDT. At the NPCC coincident peak demand New York demand was 31,766 MW. There were no fuel supply, transmission or reactive capability issues. Additional details can be found in Appendix VIII – page 31.

**Ontario**

For the fourth year in a row, September’s weather was above normal as the month started out hot and humid leading into the Labor Day weekend. This highlights the trend of summer peaks occurring later in the year and is atypical as forecasted peaks are normally predicted for the months of July and August.

Actual demand peaked on Wednesday, September 5, the hottest day of the month with temperatures reaching 33.9°C (Toronto). The demand peak (23,240 MW) was very close to the 2016 September peak of 23,213 MW on a daily high of 34.5°C. The peak was reduced by embedded solar production and ICI customer actively reducing their load at the time of the peak. This actual peak exceeded the extreme weather forecasted peak by over 1,000 MW. To ensure reliability over this period, the IESO had to defer a number of outages.

During the NPCC coincident peak, the actual peak demand was 21,935 MW. Transfers from the other areas during the NPCC coincident peak equaled approximately 300 MW.

**Québec**

The Québec Area actual internal peak demand for summer 2018 occurred on July 5, 2018 at HE18 EDT and was 21,448 MW. The Québec actual internal demand coincident to the NPCC peak was 21,010 MW. Transfers to other areas during the NPCC coincident peak were approximately 5,500 MW.

The all-time summer peak demand record is still 22,092 MW from July 2010. No resource adequacy event occurred during the 2018 Summer Operating Period.
Historical Summer Demand Review
The table below summarizes historical non-coincident summer peaks for each NPCC Balancing Authority Area over the last ten years along with the forecast normal non-coincident peak demand for summer 2019.

Table 7-1: 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 Coincident Demand</th>
<th>Date</th>
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<td>2009</td>
<td>3,566</td>
<td>25,100</td>
<td>30,843</td>
<td>24,380</td>
<td>21,141</td>
<td>102,903</td>
<td>August 17, 2009</td>
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<td>2010</td>
<td>3,497</td>
<td>27,102</td>
<td>33,452</td>
<td>25,075</td>
<td></td>
<td>22,092, 109,924</td>
<td>July 6, 2010</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>109,754</td>
<td>July 21, 2011</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>109,278</td>
<td>July 17, 2013</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>96,068</td>
<td>July 1, 2014</td>
</tr>
<tr>
<td>2017</td>
<td>3,118</td>
<td>23,708</td>
<td>29,699</td>
<td>21,786</td>
<td>21,118</td>
<td>96,911</td>
<td>June 12, 2017</td>
</tr>
<tr>
<td>2018</td>
<td>3,243</td>
<td>25,808</td>
<td>31,861</td>
<td>23,240</td>
<td>21,448</td>
<td>103,231</td>
<td>August 28, 2018</td>
</tr>
<tr>
<td>2019 Normal (50/50) Forecast</td>
<td>3,255</td>
<td>25,323</td>
<td>32,382</td>
<td>22,105</td>
<td>21,005</td>
<td>103,548</td>
<td>July 28, 2019</td>
</tr>
</tbody>
</table>
8. **2019 Reliability Assessments of Adjacent Regions**

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

[https://www.rfirst.org/about/publicreports](https://www.rfirst.org/about/publicreports)

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 2019 Summer Multi-Area Probabilistic Reliability Assessment**  
**Executive Summary**

This assessment was prepared by the CP-8 Working Group to estimate the use of the available NPCC Area Operating Procedures to mitigate resource shortages from May through September 2018 period. Please refer to Appendix VIII (page 25 – Table 9) for a description of the Base Case and Severe Case Assumptions.

**Base Case Scenario**

All Areas are not expected to use their Operating Procedures designed to mitigate resource shortages (likelihoods of less than 0.5 days/period) during the 2019 summer period for the Base Case conditions assuming the expected peak load forecast. The expected peak load level results were based on the probability-weighted average of the seven load levels simulated.

**Extreme Peak Load**

The Maritimes Area shows a likelihood of reducing their 30-min reserve (less than the chance of one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

The New England Area shows a likelihood of reducing their 30-min reserve (less than the chance of one occurrence), and also calling on voltage reduction (less than the chance of one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

The New York Area shows a likelihood of activation of their demand response programs, (less than a chance of two occurrences) and also reducing their 30-min reserve (less than a chance of one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

**Severe Case Scenario**

Only the New York Area shows a likelihood of activation of their demand response programs (chance of two occurrences), and also reducing their 30-min reserve (chance of one occurrence) during the 2019 summer period for the Severe Case conditions assuming the extreme peak load forecast. The expected peak load level results were based on the probability-weighted average of the seven load levels simulated.

The New England and New York Areas, and to a lesser extent, the Quebec, Maritimes and Ontario Areas show greater likelihoods of using all their Operating Procedures designed to mitigate resource shortages during the 2019 summer period for the Severe Case conditions assuming the extreme peak load forecast (represents the second to highest load level, having approximately a 6% chance of occurring).

---

13 Represents the second to highest load level, having approximately a 6% chance of occurring.
## Appendix I – Summer 2019 Expected Load and Capacity Forecasts

### Table AP-1 - NPCC Summary

#### Control Area Load and Capacity

<table>
<thead>
<tr>
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<td>1,066</td>
<td>2,539</td>
<td>167,652</td>
<td>83,115</td>
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<td>45,850</td>
<td>24,682</td>
<td>22,636</td>
<td>28.2%</td>
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<td>966</td>
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<td>167,652</td>
<td>83,115</td>
<td>310</td>
<td>39,599</td>
<td>8,985</td>
<td>9,910</td>
<td>45,850</td>
<td>24,682</td>
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<td>966</td>
<td>2,539</td>
<td>167,652</td>
<td>83,115</td>
<td>310</td>
<td>39,599</td>
<td>8,985</td>
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<td>45,850</td>
<td>24,682</td>
<td>22,636</td>
<td>28.2%</td>
</tr>
<tr>
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<td>2,539</td>
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<td>83,115</td>
<td>310</td>
<td>39,599</td>
<td>8,985</td>
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<td>45,850</td>
<td>24,682</td>
<td>22,636</td>
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<td>45,850</td>
<td>24,682</td>
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<tr>
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<td>24,682</td>
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<td>24,682</td>
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<td>39,599</td>
<td>8,985</td>
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<td>24,682</td>
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<td>310</td>
<td>39,599</td>
<td>8,985</td>
<td>9,910</td>
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<td>24,682</td>
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<td>9,910</td>
<td>45,850</td>
<td>24,682</td>
<td>22,636</td>
<td>28.2%</td>
</tr>
</tbody>
</table>

### Key
- Highlighted number denotes the minimum forecasted NPCC “Revised Net Margin”.
- Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.
- Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC “Revised Net Margin”.

### Notes
1. Net Interchange represents purchases and sales with Areas outside of NPCC
2. Dispatchable Demand-Side Management (DDSM) are demand resources assets that help meet an Area’s electricity needs by reducing consumption.
3. Total Capacity = Installed Capacity + Net Interchange + Dispatchable Demand Response
4. Net Margin = Total Capacity - Load Forecast + Interruptible Load - Known maintenance - Operating reserve - Unplanned Outages
5. Revised Net Margin = Net Margin - Bottled resources
### Table AP-2 – Maritimes

**Control Area Load and Capacity**

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**Key**

Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC “Revised Net Margin”.

Highlighted number denotes forecasted Summer 2019 Peak Load for Maritimes. Months of May and September are excluded.

**Notes**

(1) Known Maint./Derate include wind. The Maritimes installed wind capacity has been derated by 72 percent.

(2) Week beginning 21-Jul-19 denotes the forecasted Maritimes Summer 2019 Peak Week. Months of May and September are excluded.
### Table AP-3 – New England

| Area | ISO-NE | Revision Date | April 5, 2019 |

#### Control Area Load and Capacity

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**Key**
- Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.
- Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC “Revised Net Margin”.
- Highlighted numbers denote forecasted Summer 2019 Peak Load for ISO-NE.

**Notes**
1. Installed Capacity values based on Seasonal Claimed Capabilities (SCC) and ISO-NE Forward Capacity Market (FCM) resource obligations expected for the 2019-2020 capacity commitment period.
2. Net Interchange includes peak purchases / sales from Maritimes, Quebec and New York.
3. Preliminary load forecast assumes net Peak Load Exposure (PLE) of 25,323 MW and does include 3,066 MW credit for Energy Efficiency (EE) and 721 MW of behind-the-meter PV (BTM PV). The Summer PLE period covers the months of June through early September; developed to help mitigate the effects of abnormal weather during generator maintenance/outage scheduling and help forecast conservative operable capacity margins.
4. On peak, 340 MW of Active Demand Capacity Resource (ADCR) is considered available for economic dispatch. ADCRs can participate in New England’s Forward Capacity Market (FCM), have the ability to obtain a capacity Supply Obligation (CSO) and also participate in the Day-Ahead and Real-Time Energy Markets.
5. Includes known resource outages (scheduled and forced) as of the Revision Date listed above.
6. 2,305 MW operating reserve assumes 120% of the largest contingency of 1,400 MW and 50% of the second largest contingency of 1,250 MW.
7. Assumed unplanned outages is based on historical observation of forced outages and any additional reductions for generation at risk due to natural gas supply.
8. Includes a normal forecast unplanned outage allotment (from 2,100 MW to 3,400 MW).
9. Weeks from June through early September denote the ISO-NE summer peak load exposure - please refer to Table 4-5 for additional information.
### Table AP-4 – New York

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**Key**

- Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.
- Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC “Revised Net Margin”.
- Highlighted number denotes forecasted Summer 2019 Peak Load for NYISO.

**Notes**

1. Figures include the election of Unforced Capacity Deliverability Rights (UDRs), External CRIS Rights, Existing Transmission Capacity for Native Load (ETCNL) elections, First Come First Serve Rights (FCFSR) as currently known, and grandfathered exports. For more information on the use of UDRs, please see section 4.14 of the ICAP Manual.
2. Week beginning 28-Jul-19 denotes the New York Peak Week.
### Table AP-5 – Ontario

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<td>0</td>
<td>890</td>
<td>37,778</td>
<td>16,643</td>
<td>0</td>
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<tr>
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<td>39,061</td>
<td>22,105</td>
<td>0</td>
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<td>21,885</td>
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<td>0</td>
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<td>1,401</td>
<td>2,392</td>
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<td>1,221</td>
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<td>1,401</td>
<td>1,289</td>
<td>4,513</td>
<td>26.6%</td>
</tr>
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</table>

### Key
- Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.
- Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC "Revised Net Margin".
- Highlighted number denotes forecasted Summer 2019 Peak Load for Ontario.

### Notes
1. "Installed Capacity" includes all generation registered in the IESO-administered market.
2. "Load Forecast" represents the normal weather case, weekly 60-minute peaks.
3. "Known Maint./Derat./Bottled Cap." includes planned outages, deratings, historic hydroelectric reductions and variable generation reductions.
4. "Unplanned Outages" is based on the average amount of generation in forced outage for the assessment period.
5. Week beginning 30-Jun-19 denotes the Ontario Peak Week
## Table AP-6 – Québec

### Area
Québec

### Revision Date
April 5, 2019

### Control Area Load and Capacity

<table>
<thead>
<tr>
<th>Week Beginning</th>
<th>Installed Capacity MW</th>
<th>Net Interchange MW</th>
<th>Dispatchable DSM MW</th>
<th>Total Capacity MW</th>
<th>Load Forecast MW</th>
<th>Extreme Load Forecast</th>
<th>Historical Peak Load</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. MW</th>
<th>Seq. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
<th>Net Margin %</th>
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<td>-1,195</td>
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<td>45,482</td>
<td>22,047</td>
<td>22,577</td>
<td>23,210</td>
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<td>1,200</td>
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<td>20,922</td>
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<td>1,200</td>
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<td>13,387</td>
<td>1,500</td>
<td>1,200</td>
<td>8,252</td>
<td>39.9%</td>
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</table>

### Key
- Highlighted week beginning 28-Jul-19 denotes the NPCC forecasted coincident peak demand.
- Highlighted week beginning 05-May-19 denotes week with the largest forecasted NPCC “Revised Net Margin”.
- Highlighted number denotes forecasted Summer 2019 Peak Load for Québec. Months of May and September are excluded.

### 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 and transmission losses due to firm sales.
3. Includes 3880 MW (100%) of Wind capacity derating.
4. Week beginning 11-Aug-19 denotes the forecasted Québec Peak Week. Months of May and September are excluded.
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 and solar generation derating.

**Individual Reliability Coordinator area particularities**

*Maritimes*

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

*New England*

Installed capacity is based on generator Seasonal Claimed Capabilities (SCC) and generation anticipated to be commercial for the identified capacity period. Totals also account for the operable capacity values of renewable resources.

*New York*

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

*Ontario*

This number includes all generation registered with the IESO.

*Québec*

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

**Net Interchange**

Net Interchange is the total of Net Imports – Net Exports for NPCC and each Balancing Authority Area.
**Dispatchable Demand-Side Management**

Dispatchable Demand-Side Management (DDSM) are demand resources assets that help meet an Area’s electricity needs by reducing consumption. This is the portion of the Demand Response Programs that is accounted as capacity instead of load modifier.

**Total Capacity**

Total Capacity = Installed Capacity +/- Net Interchange + Dispatchable Demand-Side Management.

**Demand Forecast**

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

**Interruptible Loads**

Loads that are interruptible under the terms specified in a contract and are not dispatchable.

**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 planned generator outages, deratings, bottling, historic hydroelectric reduction and variable generation reductions.
Québec

This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include – 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% of the first largest contingency plus 50% of the second largest contingency.

New England

The required operating reserve consists of 120% of the first largest contingency plus 50% of the second largest contingency.

New York

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

Ontario

The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

Québec

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

Unplanned Outages

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

Individual Reliability Coordinator area particularities
**Maritimes**

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

**New England**

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

**New York**

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

**Ontario**

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

**Québec**

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

**Net Margin**

Net margin = Total capacity – Load forecast + Interruptible load – Known maintenance/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 are located in Southeast New York). Load serving entities in those regions must procure a certain amount of their capacity from generators within those regions.
**Bottled Resources**

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

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 forecasted transfer capabilities between Reliability Coordinator areas represented as Total Transfer Capabilities (TTC). It is recognized that the forecasted and actual transfer capability may differ depending on system conditions and configurations such as real-time voltage profiles, generation dispatch or operating conditions and may also account for Transmission Reliability Margin (TRM). Readers are encouraged to review information on the Available Transfer Capability (ATC) and Total Transfer Capability (TTC) between Reliability Coordinator Areas. These capabilities may not correspond to exact ATC values posted on the Open Access Same-Time Information Transmission System (OASIS) or the Reliability Coordinator’s website since the existing transmission service commitments are not considered. Area specific websites are listed below.

- **Maritimes**

- **New England**
  - [https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables](https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables)

- **New York**

- **Ontario**
  - [http://reports.ieso.ca/public/TxLimitsAllInService0to34Days/](http://reports.ieso.ca/public/TxLimitsAllInService0to34Days/)
  - [http://reports.ieso.ca/public/TxLimitsOutage0to2Days/](http://reports.ieso.ca/public/TxLimitsOutage0to2Days/)
  - [http://reports.ieso.ca/public/TxLimitsOutage3to34Days/](http://reports.ieso.ca/public/TxLimitsOutage3to34Days/)

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

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC at Interconnection Points (MW)</th>
<th>ATC under Specified Conditions (MW)</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eel River (NB)/Matapédia (QC)</td>
<td>335</td>
<td>335</td>
<td>Eel River HVDC (capable of 350 MW) reduced by 15 MW due to losses. When Eel River converter losses and line losses to the Québec border are taken into account, Eel River to Matapédia transfer is 335 MW.</td>
</tr>
<tr>
<td>Edmundston (NB)/Madawaska (QC)</td>
<td>400</td>
<td>350</td>
<td>Madawaska HVDC derated to 350 MW due to temperature. (30 °C (86 °F))</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>735</strong></td>
<td><strong>685</strong></td>
<td>The NB to HQ-HVDC transfer capability is limited to 650 MW due to Load loss limitations in the Maritimes.</td>
</tr>
<tr>
<td>New England</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keswick (3001 line), Point Lepreau (390/3016 line)</td>
<td>1000</td>
<td>1000</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1000</strong></td>
<td><strong>1000</strong></td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from New England to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maritimes</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keswick (3001 line), Point Lepreau (390/3016 line)</td>
<td>550</td>
<td>550</td>
<td>Transfer capability depends on operating conditions in northern Maine and the Maritimes area. If key generation or capacitor banks are not operational, the transfer limits from New England to New Brunswick will decrease. At present, the NBP-SO has limited the transfer to 200 MW but will increase it to 550 MW on request from the NBP-SO under emergency operating conditions for up to 30 minutes. This limitation is due to system security/stability within New Brunswick.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>550</td>
<td>550</td>
<td></td>
</tr>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)</td>
<td>1,310</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>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.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,840</td>
<td>1,840</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase II HVDC link (451 and 452 lines)</td>
<td>1,200</td>
<td>1,200</td>
<td>Export capability of the facility is 1,200 MW.</td>
</tr>
<tr>
<td>Highgate (VT) – Bedford (BDF) Line 1429</td>
<td>170</td>
<td>100</td>
<td>Capability of the tie is 225 MW but at times, conditions in Vermont limit the capability to 100 MW or less. The DOE permit is 170 MW.</td>
</tr>
<tr>
<td>Derby (VT) – Stanstead (STS) Line 1400</td>
<td>0</td>
<td>0</td>
<td>Though there is no capability scheduled to export to Québec through this interconnection path, exports may be able to be provided, dependent upon New England system load levels and generation dispatch. ISO-NE planning assumptions are based on a path limit of 0 MW.</td>
</tr>
</tbody>
</table>
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.
## Transfers from New York to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (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 (393, 398, E205W, PV20, K7, K6 and 690 lines)</td>
<td>1,600</td>
<td>1,400</td>
<td>New York applies a 200 MW Transmission Reliability Margin (TRM).</td>
</tr>
<tr>
<td>LI / Connecticut Northport-Norwalk Harbor Cable</td>
<td>200</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>LI / Connecticut Cross-Sound Cable</td>
<td>330</td>
<td>330</td>
<td>Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,130</td>
<td>1,930</td>
<td></td>
</tr>
<tr>
<td><strong>Ontario</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines PA301, PA302, BP76, PA27, L33P, L34P</td>
<td>1,700</td>
<td>1,400</td>
<td>New York applies a 300 MW Transmission Reliability Margin (TRM). Thermal limits on the QFW interface may restrict exports to lesser values when the generation in the Niagara area is taken into account.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,130</td>
<td>1,930</td>
<td></td>
</tr>
<tr>
<td><strong>PJM</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PJM AC Ties</td>
<td>1,350</td>
<td>1,050</td>
<td>New York applies a 300 MW Transmission Reliability Margin (TRM).</td>
</tr>
<tr>
<td>NYC/PJM Linden VFT</td>
<td>315</td>
<td>315</td>
<td></td>
</tr>
<tr>
<td>LI/PJM Neptune Cable</td>
<td>0</td>
<td>0</td>
<td>The Neptune DC cable is uni-directional into New York.</td>
</tr>
<tr>
<td>NYC/PJM HTP DC/DC Tie</td>
<td>0</td>
<td>0</td>
<td>The HTP DC/DC tie is uni-directional into New York.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,665</td>
<td>1,365</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chateauguay (QC)/Massena (NY)</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>Cedars / Québec</td>
<td>40</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,040</td>
<td>1,040</td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from Ontario to Interconnection Point

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines PA301, PA302, BP76, PA27, L33P, L34P</td>
<td>1,950</td>
<td>1,750</td>
<td>The TRM is 200 MW.</td>
</tr>
<tr>
<td>Total</td>
<td>1,950</td>
<td>1,750</td>
<td></td>
</tr>
<tr>
<td>MISO Michigan</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines L4D, L51D, J5D, B3N</td>
<td>1,700</td>
<td>1,500</td>
<td>The TRM is 200MW.</td>
</tr>
<tr>
<td>Total</td>
<td>1,700</td>
<td>1,500</td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NE / RPD – KPW Lines D4Z, H4Z</td>
<td>95</td>
<td>85</td>
<td>The 95 MW reflects an agreement through the TE-IESO Interconnection Committee. The TRM is 10 MW.</td>
</tr>
<tr>
<td>Ottawa / BRY – PGN Lines P33C, X2Y, Q4C</td>
<td>120</td>
<td>120</td>
<td>There is no capacity to export to Québec through Lines P33C and X2Y.</td>
</tr>
<tr>
<td>Ottawa / Brookfield Lines D5A, H9A</td>
<td>200</td>
<td>190</td>
<td>Only one of H9A or D5A can be in service at any time. The TRM is 10 MW.</td>
</tr>
<tr>
<td>East / Beau Lines B5D, B31L</td>
<td>470</td>
<td>470</td>
<td>Capacity from Saunders that can be synchronized to the Hydro-Québec system.</td>
</tr>
<tr>
<td>HAW / OUTA Lines A41T , A42T</td>
<td>1,250</td>
<td>1,230</td>
<td>The TRM is 20 MW.</td>
</tr>
<tr>
<td>Total</td>
<td>2,135</td>
<td>2,095</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>225</td>
<td>200</td>
<td>The TRM is 25 MW.</td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>150</td>
<td>140</td>
<td>The TRM is 10 MW.</td>
</tr>
<tr>
<td>Total</td>
<td>375</td>
<td>340</td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from Québec to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (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 reviewed annually. Madawaska HVDC derated to 350 MW due to temperature. (30 °C / 86 °F) plus available radial load transfers. Transfer amount is dependent on local loading and is reviewed annually.</td>
</tr>
<tr>
<td>Madawaska (QC)/Edmundston (NB)</td>
<td>391 + radial loads</td>
<td>350 + radial loads</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>741 + radial loads</td>
<td>700 + radial loads</td>
<td>Radial load transfer amount is dependent on local loading and is updated monthly and reviewed annually.</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>2,000</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) Line 1429</td>
<td>225</td>
<td>225</td>
<td>Capacity of the Highgate HVDC facility is 225 MW</td>
</tr>
<tr>
<td>Stanstead (STS) – Derby (VT) Line 1400</td>
<td>50</td>
<td>50</td>
<td>Normally only 35 MW of load in New England is connected.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,275</td>
<td>2,275</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>1,800</td>
<td>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>
<tr>
<td>Les Cèdres (QC)/Dennison (NY)</td>
<td>190</td>
<td>190</td>
<td>Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 190 MW and 160 MW respectively (during the summer). However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,990</td>
<td>1,990</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Ontario</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Les Cèdres (QC)/Cornwall (Ont.)</td>
<td>160</td>
<td>160</td>
<td>Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 190 MW and 160 MW respectively (during the summer). However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.</td>
</tr>
<tr>
<td>Location</td>
<td>Transfer Capacity (MW)</td>
<td>Note</td>
<td></td>
</tr>
<tr>
<td>-----------</td>
<td>-------------------------</td>
<td>------</td>
<td></td>
</tr>
<tr>
<td>Beauharnois(QC)/St-Lawrence (Ont.)</td>
<td>800</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Brookfield/Ottawa (Ont.)</td>
<td>200</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Only one of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A. The 200 MW reflects the maximum transfer available from Brookfield to Ontario. D5A’s transfer limit is 200 MW during the summer period.</td>
<td></td>
</tr>
<tr>
<td>Rapide-des-Iles (QC)/Dymond (Ont.)</td>
<td>55</td>
<td>55</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>This represents Line D4Z capacity in summer. There is no capacity to export to Ontario through Line H4Z.</td>
<td></td>
</tr>
<tr>
<td>Bryson-Paugan (QC)/Ottawa (Ont.)</td>
<td>335</td>
<td>335</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Capability of line P33C is 270 MW and the X2Y capability is 65 MW (at 30 °C / 86 °F). There is no capacity to export to Ontario through Line Q4C.</td>
<td></td>
</tr>
<tr>
<td>Outaouais (Qc)/Hawthorne (Ont.)</td>
<td>1,250</td>
<td>1,250</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>HVDC back-to-back facility at Outaouais.</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,800</strong></td>
<td><strong>2,800</strong></td>
<td></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 Quebec and its neighbors for the 2018 Summer Operating Period.
## Transfers from Regions External to NPCC

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>TTC (MW)</th>
<th>ATC (MW)</th>
<th>Rationale for Transfer Capability</th>
</tr>
</thead>
<tbody>
<tr>
<td>MISO (Michigan) / ONT Lines L4D, L51D, J5D, B3N</td>
<td>1,700</td>
<td>1,500</td>
<td>Represents a worst-case scenario for the implementation of Policy on operation.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,700</td>
<td>1,500</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>MISO (Manitoba-Minnesota) / ONT NW / MAN Lines K21W, K22W</td>
<td>293</td>
<td>268</td>
<td>The TRM is 25 MW.</td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>100</td>
<td>80</td>
<td>The TRM is 20 MW.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>393</td>
<td>348</td>
<td></td>
</tr>
<tr>
<td>PJM / New York</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AC Ties</td>
<td>2,100</td>
<td>1,800</td>
<td>The TRM is 300 MW</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>3,735</td>
<td>3,435</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% 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% (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models. Nova Scotia uses 5% as the Extreme Load Forecast Margin while the rest of the Maritimes uses 9% after similar analysis on their part.
New England

ISO New England’s long-term 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 long-term 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\(^{14}\), which has a 50% 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 40 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% chance of being exceeded, is associated with weather at the time of the winter peak of 1.6 °F and summer peak of 94.2 °F.

From a short-term load forecast perspective, 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 Artificial 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 conducts load forecasting for the NYCA and for localities within the NYCA. The NYISO employs a two-stage process to develop load forecasts for each of the eleven zones within the NYCA. In the first stage, zonal load forecasts are based upon econometric

\(^{14}\) Additional information describing ISO New England’s load forecasting may be found at https://www.iso-ne.com/system-planning/system-plans-studies/celt
projections. These forecasts assume a conventional portfolio of appliances and electrical technologies. The forecasts also assume that future improvements in energy efficiency measures will be similar to those of the recent past and that spending levels on energy efficiency programs will be similar to recent history. In the second stage the NYISO adjusts the econometric forecasts to explicitly reflect a projection of the energy savings resulting from statewide energy efficiency programs, impacts of new building codes and appliance efficiency standards and a projection of energy usage due to electric vehicles. The baseline forecasts include the load-reducing impacts of energy efficiency programs, building codes, and appliance efficiency standards solar PV and distributed energy generation. The actual impact of solar PV varies considerably by hour of day. The hour of the NYCA peak varies yearly. The forecast of solar PV-related reductions in summer peak assumes that the NYCA peak occurs from 4 p.m. to 5 p.m. EDT in late July. The forecast of solar PV-related reductions in winter peak is zero because the sun sets before the assumed peak hour of 6 p.m. EST.

In addition to the baseline forecast, the NYISO also produces high and low forecasts for each zone that represent extreme weather conditions. The forecast is developed by the NYISO using a Temperature-Humidity Index (THI) which is representative of normal weather during peak demand conditions. The weather assumptions for most regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

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

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

The Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by non-registered generation. The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic data, calendar variables, conservation and embedded generation. 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.

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 is decremented from the demand forecast, which includes demand reductions due to energy efficiency, fuel switching and conservation behaviour (including the impact smart meters).

In Ontario, demand management programs include Demand Response programs and the dispatchable loads program. Historical data is used to determine the quantity of reliably available capacity, which is treated as a resource to be dispatched.
Embedded generation leads to a reduction in “on-grid” demand on the grid, which is decremented from the demand forecast.
Ontario uses 31 years of history to calculate a weather factor to represent the MW impact on demand if the weather conditions (temperature, wind speed, cloud cover and humidity) are observed in the forecast horizon. Weather is sorted on a monthly basis, and for the extreme weather scenario, Ontario uses the maximum value from the sorted history.

The variable generation capacity in Table 4 is the total installed capacity expected during the operating period, with the variable generation resources expected in-service outlined in Table 3. For determining wind and solar derating factors, Ontario uses seasonal contribution factors based upon median historical hourly production values.

Québec

Hydro-Québec’s peak demand and energy-sales forecasting is the responsibility of Hydro-Québec Distribution.

The energy-sales forecast combines the forecasting results of four different sectors: residential, commercial, small and medium-size industrial, and large industrial. The type of model used for forecasting energy-sales differs for each sector and is based on end-use and/or econometric models. Specifically, they consider weather variables, econometric forecasts, demographics, energy efficiency and different information about large customers. The forecast is normalized to account for weather conditions based on an historical trend weather analysis. The total energy requirements are obtained by adding transmission and distribution losses to the forecasts.

The monthly peak demand model is a regression between historical peak and end-use and/or sector sale. The peak demand forecast is obtained by applying the regression model to the forecasted end-use and/or sector sale.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 47 years of temperature data (1971-2017), adjusted by 0.3 °C (0.5 °F) per decade starting in 1971 to account for climate change. In addition, each year of historical climatic data is shifted up and down by 3 days to capture extreme weather conditions that could have occurred during either a weekend or a weekday. This approach produces a set of 329 different demand scenarios. The base case scenario is the average of the peak hour for all 329 scenarios. Load uncertainty pertains to economic and demographic uncertainties, and also to specific risks associated with large customers.
Overall Uncertainty (OU) is defined as the independent combination of climatic and load uncertainties. The OU, expressed as a percentage of standard deviation over total demand, is lower during the summer than during the winter. For instance, during the summer, the uncertainty associated with peak weather conditions is about 450 MW and is equivalent to one standard deviation. Conversely, the uncertainty increases to 1,450 MW during the winter.

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

NPCC Directories Pertinent to Operations

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

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

NPCC Regional Reliability Reference Directory #2 - Emergency Operations

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

NPCC Regional Reliability Reference Directory #5 – Reserve

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

- Note: This document is currently under review.

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.

- Note: This document is currently under review.

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:** This document will be retired in 2019 when NERC MOD-025 is fully implemented.

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:** This document will be retired in 2019 when NERC MOD-025 is fully implemented.

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.
• **Note:** This document is currently under review.

**NPCC Procedures Pertinent to Operations**

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

Description: This document details the procedures for the NPCC Emergency Preparedness Conference Calls, which establish communications among the Operations Managers of the Reliability Coordinator (RC) Areas which discuss issues related to the adequacy and security of the interconnected bulk power supply system in NPCC.

**C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems**

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

**C-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-Québec

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

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

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

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

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

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

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

ReliabilityFirst Corporation
   http://www.rfirst.org
Appendix VII - References

NPCC Reliability Assessments

https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx
Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment

For

Summer 2019

Approved by the TFCP

April 15, 2019

Conducted by the

NPCC CP-8 Working Group
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1. EXECUTIVE SUMMARY

This report, which was prepared by the CP-8 Working Group, estimates the use of the available NPCC Area Operating Procedures to mitigate resource shortages from May through September 2018 period.

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

The assumptions used in this probabilistic study are consistent with the CO-12 Working Group’s study, *NPCC Reliability Assessment for Summer 2019*, April 2019, and are summarized in Table 1.

<table>
<thead>
<tr>
<th>Area</th>
<th>Expected Peak ² (MW)</th>
<th>Extreme Peak ³ (MW)</th>
<th>Available Capacity ⁴ (MW)</th>
<th>Peak Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec (QC)</td>
<td>22,183</td>
<td>24,525</td>
<td>36,955</td>
<td>May</td>
</tr>
<tr>
<td>Maritimes Area (MT)</td>
<td>3,367</td>
<td>3,676</td>
<td>7,152</td>
<td>May</td>
</tr>
<tr>
<td>New England (NE)</td>
<td>25,323</td>
<td>29,125</td>
<td>32,584</td>
<td>August</td>
</tr>
<tr>
<td>New York (NY)</td>
<td>32,429</td>
<td>35,189</td>
<td>42,422</td>
<td>August</td>
</tr>
<tr>
<td>Ontario (ON)</td>
<td>22,105</td>
<td>24,632</td>
<td>29,459</td>
<td>July</td>
</tr>
</tbody>
</table>

The study was conducted for two load scenarios: expected peak load level scenario and extreme peak load level scenario. The expected peak load level was based on each Area’s projection of mean demand, while the extreme peak load level represents the second highest peak load level of the seven levels simulated (see section 3.1.2). The extreme peak load level has a six percent chance of occurring. While the extreme peak load, as defined for this study, may be different than the extreme peak load defined by the Areas in their own studies, the Working Group finds this peak load level appropriate for providing an assessment of extreme conditions within NPCC. Details

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1. See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx.
2. The expected peak load forecast represents each Area’s projection of mean demand over the study period based on historical data analysis. New England’s peak value takes into account the impacts from the behind-the-meter PV load reduction, and passive demand resources.
3. The extreme peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence. New England’s peak value takes into account the impacts from the behind-the-meter PV load reduction, and passive demand resources.
4. Available Capacity represents Area’s effective capacity at the time of the peak; it takes into account firm imports and exports, and reductions due to deratings. New England capacity includes active demand capacity resources and net capacity imports. New York capacity includes SCR resources and imports.
of information provided by each Area for their respective peak load forecasts are presented in Section 3.1 of this report.

For each of the two demand scenarios described above, two different system conditions were considered: Base Case assumptions and Severe Case assumptions. Details regarding the two sets of assumptions are described in Section 3.7 of the report.

Table 2 shows the estimated use of Operating Procedures under the Base Case assumptions for the expected peak load level and the extreme peak load level scenarios for the May – September 2018 period. Occurrences greater than 0.5 days/period are highlighted.  

| Table 2: Expected Use of the Operating Procedures under Base Case Assumptions (days/period) |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
|                 | QC | MT | NE | NY | ON | QC | MT | NE | NY | ON |
| Expected Load Level |     |     |     |     |     |     |     |     |     |     |
| Extreme Load Level |     |     |     |     |     | 1.403 | 0.127 |
| Activation of DR/SCR | - | - | - | 0.123 | 0.008 | - | - | - | 1.403 | 0.127 |
| Reduce 30-min Reserve | - | 0.123 | 0.064 | 0.056 | - | - | 0.826 | 0.956 | 0.618 | 0.006 |
| Initiate Interruptible Loads/Voltage Reduction 6 | - | 0.041 | 0.037 | 0.021 | - | - | 0.314 | 0.552 | 0.232 | - |
| Reduce 10-min Reserve 7 | - | - | 0.024 | 0.006 | - | - | 0.001 | 0.361 | 0.073 | - |
| Appeals | - | - | 0.024 | 0.005 | - | - | - | 0.361 | 0.064 | - |
| Disconnect Load | - | - | 0.006 | - | - | - | - | 0.095 | 0.012 | - |

No Areas show likelihoods greater than 0.5 days/period highlighted in Table 2) of using their Operating Procedures designed to mitigate resource shortages during the 2019 summer period for the Base Case conditions assuming the expected load forecast.

Likelihoods greater than 0.5 days/period that the Maritimes, New England and New York have of using their respective Operating Procedures designed to mitigate resource shortages (activating

---

5 Rounded to the nearest whole occurrence, likelihoods of less than 0.5 days/period are not considered significant.
6 Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
7 New York initiates Appeals prior to reducing 10-min Reserve.
demand response, reducing 30-min reserve, voltage reduction) during the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast (represents the second to highest load level, having approximately a 6% chance of occurring) are also highlighted in Table 2.

Table 3 shows the estimated use of Operating Procedures under the Severe Case assumptions for the expected peak load level and the extreme peak load level scenarios for the May - September 2018 period. Occurrences greater than 0.5 days/period are highlighted.  

Table 3: Expected Use of the Operating Procedures under Severe Case Assumptions (days/period)

<table>
<thead>
<tr>
<th>Procedure</th>
<th>QC</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
<th>QC</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expected Load Level</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Activation of DR/SCR</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2.018</td>
<td>0.395</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>11.801</td>
<td>4.930</td>
</tr>
<tr>
<td>Reduce 30-min Reserve</td>
<td>-</td>
<td>0.313</td>
<td>0.257</td>
<td>1.045</td>
<td>0.208</td>
<td>-</td>
<td>1.890</td>
<td>3.850</td>
<td>8.759</td>
<td>2.799</td>
</tr>
<tr>
<td>Initiate Interruptible Loads/Voltage Reduction 8</td>
<td>-</td>
<td>0.114</td>
<td>0.132</td>
<td>0.476</td>
<td>0.094</td>
<td>-</td>
<td>0.735</td>
<td>1.981</td>
<td>5.716</td>
<td>1.359</td>
</tr>
<tr>
<td>Reduce 10-min Reserve</td>
<td>-</td>
<td>-</td>
<td>0.100</td>
<td>0.198</td>
<td>0.015</td>
<td>-</td>
<td>0.002</td>
<td>1.493</td>
<td>2.780</td>
<td>0.225</td>
</tr>
<tr>
<td>Appeals</td>
<td>-</td>
<td>-</td>
<td>0.099</td>
<td>0.158</td>
<td>0.001</td>
<td>-</td>
<td>-</td>
<td>1.487</td>
<td>2.243</td>
<td>0.020</td>
</tr>
<tr>
<td>Disconnect Load</td>
<td>-</td>
<td>-</td>
<td>0.055</td>
<td>0.043</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.825</td>
<td>0.634</td>
<td>0.005</td>
</tr>
<tr>
<td><strong>Extreme Load Level</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Likelihoods greater than 0.5 days/period that New York has of using their respective Operating Procedures designed to mitigate resource shortages (activating demand response and reducing 30-min reserve) during the 2019 summer period for the Severe Case conditions assuming the expected load forecast are highlighted in Table 3.

Likelihoods greater than 0.5 days/period that New York, New England, and Ontario have of using their respective Operating Procedures designed to mitigate resource shortages during the 2019 summer period are also highlighted in Table 3 for the Severe Case conditions assuming the extreme peak load forecast (represents the second to highest load level, having approximately a 6% chance of occurring).

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8 Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.

9 New York initiates Appeals prior to reducing 10-min Reserve.
2. INTRODUCTION

This report was prepared by the CP-8 Working Group and estimates the use of NPCC Area Operating Procedures designed to mitigate resource shortages from May through September 2018.

The development of this CP-8 Working Group’s assessment is 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 CP-8 Working Group’s efforts are consistent with the NPCC CO-12 Working Group’s study, *NPCC Reliability Assessment for Summer 2019*, April 2019. The CP-8 Working Group's Objective, Scope of Work, and Project Schedule is shown in Appendix A.

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was used for the analysis and GE Energy was retained by NPCC to conduct the probabilistic simulations. APPENDIX C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 3.22.8 was used for this reliability assessment.
3. STUDY ASSUMPTIONS

The database developed by the CP-8 Working Group for the *NPCC 2018 Long Range Adequacy Overview* 10 was used as the starting point for this reliability analysis. Working Group members reviewed the existing data and made revisions to reflect system conditions expected for the 2019 summer period.

3.1 Demand

3.1.1 Load Assumptions

Each area provided annual or monthly peak and energy forecasts for 2019 Summer. Table 4 summarizes each Area’s summer expected peak load assumptions for the study period.

<table>
<thead>
<tr>
<th>Area</th>
<th>Month</th>
<th>Peak Load (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td>May</td>
<td>22,183</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td>May</td>
<td>3,367</td>
</tr>
<tr>
<td>New England</td>
<td>August</td>
<td>25,323 11</td>
</tr>
<tr>
<td>New York</td>
<td>August</td>
<td>32,429</td>
</tr>
<tr>
<td>Ontario</td>
<td>July</td>
<td>22,105</td>
</tr>
</tbody>
</table>

Specifics related to each Area’s peak demand forecast used in this assessment are described below.

**Maritimes**

The Maritimes Area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine sub-area which uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modelling, and end use modeling to develop their load forecasts. Load forecast uncertainty is modeled in the Area’s resource adequacy analysis. The load forecast

10 See: [https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%202017LongRangeOverview(December%205%202017).pdf](https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%202017LongRangeOverview(December%205%202017).pdf).

11 This is the expected net peak reflecting the impacts from the Behind-the-Meter PV and the passive demand response resources.
uncertainty factors were developed by applying statistical methods to a comparison of historical forecast values of load to the actual loads experienced.

**New England**  
ISO New England’s long-term 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 long-term peak load model is a monthly model of the typical daily peak demand for each month, and produces forecasts of weekly, monthly, and seasonal peak demands over a 10-year time period. Daily peak demands 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 demand to weather due to the increasing cooling load.

The reference (50/50) 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 demand. The weekly weather distributions are built using 25 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 peak demand forecast, which has a 10 percent chance of being exceeded, is associated with weather at the time of the winter peak of 1.6 °F and summer peak of 94.2 °F.

The preliminary gross 50/50 summer peak demand forecast is 28,934 MW \(^{12}\) for the summer of 2019. This gross summer peak demand reflects a forecast of peak demand for New England system without accounting for the reductions from passive demand resources (PDR) and behind-the-meter PV (BTM PV). Active demand resources, PDR and BTM PV are reconstituted into the historical hourly loads to ensure the proper accounting of impacts from these resources, which are both forecast separately. The gross energy and summer peak demand forecast were revised downward from the last years to reflect the updated macroeconomic outlook, and the re-estimated econometric models with the inclusion of the 2018 historical data, and an improvement to the forecast model the exclusion of 2002 historical data. The peak reduction from the BTM PV is about 708 MW. Passive demand resources are expected to be around 2,912 MW.

New York
The New York ISO employs a multi-stage process in developing load forecasts for each of the eleven zones within the New York Control Area. In the first stage, baseline energy and peak models are built based on projections of end-use intensities and economic variables. End-use intensities modeled include those for lighting, refrigeration, cooking, heating, cooling, and other plug loads. Appliance end-use intensities are generally defined as the product of saturation levels (average number of units per household or commercial square foot) and efficiency levels (energy usage per unit or a similar measure). End-use intensities specific to New York are estimated from appliance saturation and efficiency levels in both the residential and commercial sectors. These intensities include the projected impacts of energy efficiency programs and improved codes & standards. Economic variables considered include GDP, households, population, and commercial and industrial employment. In the second stage, the incremental impacts of behind-the-meter solar PV, energy storage and distributed generation are deducted from the forecast, and the incremental impacts of electric vehicle usage are added to the forecast. In the final stage, the New York ISO aggregates load forecasts by Load Zone (referenced in the rest of this document as “Zone”).

These forecasts are based on information obtained from the New York State Department of Public Service, the New York State Energy Research and Development Authority, state power authorities, Transmission Owners, the U.S. Census Bureau, and the U.S. Energy Information Administration. The baseline and topline forecasts reflect a combination of information provided by Transmission Owners for their respective territories and forecasts prepared by the New York ISO.

Ontario
The Ontario IESO demand forecast includes the impact of conservation, time-of-use rates, and other price impacts, as well as the effects of embedded (distribution connected) generation. However, the demand forecast does not include the impacts of “controllable” demand response programs such as dispatchable loads, and demand response. The capacity from these programs is treated as resource.

Québec
The load forecast was consistent with the “Québec 2018 NPCC Interim Review of Resource Adequacy.” 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

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13 Additional information describing Ontario’s demand forecasting may be found at: [http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook](http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook)
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 47-year database of temperatures (1971-2017), 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 329 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of these 329 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 1,530 MW.

3.1.2 Load Model in MARS

The loads for each Area were modeled on an hourly, chronological basis, using the 2002 load shape. The MARS program modified the hourly loads through time to meet each Area's specified peaks and energies.

Currently, the CP-8 Working Group uses the historical load shape based on the summer of 2002 for the months of May – September. The selection of the summer load shape assumption is reevaluated on a periodic basis. Based on the latest review, the NPCC Task Force on Coordination of Planning agreed with the CP-8 Working Group’s recommendation to continue assuming the 2002 load shape for the months of May to September for NPCC probabilistic reliability assessments.

14 See: https://www.npcc.org/Library/Other/Forms/Public%20List.aspx.
Figure 1 shows the diversity in the NPCC area monthly peak load shapes used in this analysis, with the 2002 load shape assumption.

**Figure 1: 2018 Projected Monthly Peak Loads for NPCC**

The effects on reliability of uncertainties in the peak load forecast due to weather and/or economic conditions are captured through the load forecast uncertainty model within MARS program.

The NPCC Areas provide a projection for peak loads and energies that are modified by the 2002 load shape to meet the provided peak and energy targets; the Load Forecast uncertainty is determined by each NPCC Area and is illustrated in Table 5.

The program computes the reliability indices at each of the specified load levels and calculates weighted-average values based on input probabilities of occurrence. For this study, seven load levels were modeled based on the monthly peak load forecast uncertainty provided by each Area.

For example, if the Expected Load July monthly peak load for Ontario is “y”, then the Extreme Load value assumed for that month based on Table 5 would be calculated as y*1.120.

The seven peak load levels represent the expected peak load level and one, two and three standard deviations above and below that expected peak load level.
In computing the reliability indices, all Areas were evaluated simultaneously at the corresponding load level, the main assumption being that the factors giving rise to the uncertainty affect all the Areas at the same time. The amount of the effect can vary according to the variations in the peak load levels.

Table 5 shows the load variation assumed for each of the seven load levels modeled and the probability of occurrence for the summer peak month in each Area. The probability of occurrence is the weight given to each of the seven load levels; it is equal to half of the sum of the two areas on either side of each standard deviation point under the probability distribution curve.

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
<th>Probability of Occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>QC</td>
<td>1.106 1.106 1.053 1.000 0.952 0.919 0.894</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
<tr>
<td>MT</td>
<td>1.138 1.092 1.046 1.000 0.954 0.908 0.862</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
<tr>
<td>NE</td>
<td>1.260 1.130 0.974 0.974 0.897 0.886 0.851</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
<tr>
<td>NY</td>
<td>1.119 1.085 1.042 0.992 0.935 0.877 0.822</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
<tr>
<td>ON</td>
<td>1.149 1.114 1.060 1.001 0.936 0.868 0.839</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
</tbody>
</table>

The results for this study are reported for two peak load conditions: expected and extreme. The values for the expected peak 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 peak load conditions provide a measure of the reliability in the event of higher than expected peak loads and were computed for the second-to-the-highest load level. They represent a peak load level that is two standard deviation higher than the peak expected load level, with a six percent probability of occurrence. These values are highlighted in Table 5.

15 Based on 2018 forecast values.
While the extreme peak load as defined for this study may be different than the extreme peak load defined by the Areas within their own studies, the Working Group finds these peak load levels are appropriate for a probabilistic reliability assessment of the extreme conditions in NPCC.

### 3.2 Resources

Table 6 below summarizes the 2019 summer capacity assumptions for each the NPCC Areas modeled in the analysis for the Base Case Scenario; the assumptions are consistent with the assumptions used in the NPCC CO-12 Working Group’s, *NPCC Reliability Assessment for Summer 2019*, dated April 2019.

Additional adjustments were made for the Severe Scenario, as explained in Section 3.7 of this report.

<table>
<thead>
<tr>
<th>Table 6: Resource Assumptions at 2019 Summer Peak - Base Case (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>QC</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>Assumed Capacity 16</td>
</tr>
<tr>
<td>Demand Response 17</td>
</tr>
<tr>
<td>Net Imports 18</td>
</tr>
<tr>
<td>Peak Load</td>
</tr>
<tr>
<td>Reserve (%) 19</td>
</tr>
<tr>
<td>Scheduled Maintenance 20</td>
</tr>
</tbody>
</table>

Details regarding the NPCC Area’s assumptions for generating unit availability are described in the respective Area’s most recent *NPCC Comprehensive Review of Resource Adequacy*. The MARS modelling details for each type of resource in each Area are provided in Appendix D of the report.

In addition, the NPCC Areas provided the following:

---

16 Assumed Capacity - the total generation capacity assumed to be installed at the time of the summer peak.

17 Demand Response: the amount of “controllable” demand expected to be available for reduction at the time of peak demand. New England’s value reflects the amount of active demand capacity resources. New York value represents the Special Case Resource (SCR) amount.

18 Net Imports: the amount of expected firm, long-firm imports at the time of the summer peak. The value is positive for imports and negative for exports.

19 Reserve = ((Capacity + Net imports + Demand Response) – Peak Load) / Peak Load.

20 Maintenance scheduled at time of peak.

21 See: [https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx](https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx).
New England
The generating resources include the existing units and planned resources that are expected to be available for the 2019 summer period, and their ratings are based on their Seasonal Claimed Capability. Settlement Only Generating resources are not included in this assessment, however, they do participate in the Energy Market and help serve New England’s system loads. Bridgeport Harbor 5, a new combined cycle generation unit of 510 MW, and Canal 3, a new gas turbine unit of 330 MW, are assumed to be in-service in the summer. The Pilgrim Nuclear Power Station (~677 MW) is retiring before the summer of 2019.

The resources assumed in this assessment also include 493 MW of active demand capacity resources and 1,358 MW of net firm capacity imports from the neighboring areas. These demand resources and firm imports are based on their Capacity Supply Obligations associated with the 3rd annual Reconfiguration Auction for Capacity Commitment Period of 2019-2020. 22

New York

Ontario
Generating unit availability was based on the Ontario IESO *Reliability Outlook - An Adequacy Assessment of Ontario’s Electricity System from April 2019 to September 2020*, dated March 20, 2019. 25

Québec
The planned resources are consistent with the *Québec 2018 NPCC Interim Review of Resource Adequacy*. The planned outages for the summer period are reflected within this reliability assessment. The number of planned generating unit outages is consistent with observed historical values.

Maritimes
Generating unit availability reflects planned outages forecast to occur during the summer period.

3.3 Transfer Limits

Figure 2 depicts the transmission system that was modeled within this reliability assessment, showing both Area and assumed Base Case transfer limits for the summer 2019 period.

Maritimes

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected internally only to New Brunswick. Only New Brunswick is interconnected externally with Québec and USA Maine areas.

New England

The New England transmission system consists of mostly 115 kV, 230 kV, and 345 kV transmission lines, which are in northern New England generally are longer and fewer in number than in southern New England. The region has 13 interconnections with neighboring power systems. Nine interconnections are with New York (two 345 kV ties; one 230 kV tie; one 138 kV tie; three 115 kV ties; one 69 kV tie; and one 330 MW, ±150 kV high-voltage direct-current (HVDC) tie—the Cross-Sound Cable interconnection).

New England and the Maritimes (New Brunswick Power Corporation) are connected through two 345 kV AC ties, the second of which was placed in service in December 2007. New England also has two HVDC interconnections with Québec (Hydro-Québec). One is a 120 kV AC interconnection (Highgate in northern Vermont) with a 225 MW back-to-back converter station, which converts alternating current to direct current and then back to alternating current. The second is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (i.e., Phase II) and 1,200 MW of reverse export capability.

Over the years, New England has upgraded the transmission system to address the region’s reliability needs. These transmission improvements have reinforced the overall reliability of the Bulk Electric System and reduced transmission congestion, enabling power to flow more easily and efficiently around the entire region. These improvements support decreased energy production costs and increased power system flexibility. The Coopers Mills STATCOM (static synchronous condenser) is a component of the Greater Boston Reliability Project that identified transmission reinforcements required in the Boston area to reliably continue to serve the area’s increasing load. The Ascutney SVC will improve local southern Vermont voltage support for local area load support. The Farmwood synchronous condensers are two −13/+25 MVAr units (total −26 / +50 MVAr) interconnected to the Farmwood 115 kV bus in central New Hampshire. They will improve local central New Hampshire voltage support for local area load support.

New York

The New York wholesale electricity market is divided into 11 pricing or load zones and is interconnected to Ontario, Quebec, New England, and PJM. The transmission network is
Appendix VIII - CP-8 2019 Summer Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

comprised of 765 kV, 500 kV, 345 kV, 230 kV as well as 138 kV and 115 kV lines. These transmission lines exceed 11,000 circuit miles in total.

**Ontario**
The Ontario transmission system is mainly comprised of a 500 kV transmission network, a 230 kV transmission network, and several 115 kV transmission networks. It is divided into ten zones and nine major internal interfaces in the Ontario transmission system. Ontario has interconnections with Manitoba, Minnesota, Québec, Michigan, and New York.

**Québec**
The Québec Area is a separate Interconnection from the Eastern Interconnection, into which the other NPCC Areas are interconnected. TransÉnergie, the main Transmission Owner and Operator in Québec, has interconnections within Ontario, New York, New England, and the Maritimes.

There are back to back HVDC links with New Brunswick at Madawaska and Eel River, with New England at Highgate (in New England) and with New York at Châteauguay. The Radisson – Nicolet – Sandy Pond HVDC line interconnects Québec with New England. Radial load can be picked up in the Maritimes by Québec at Madawaska and at Eel River and at the Stanstead substation feeding Citizen’s Utilities in northern New England. Moreover, in addition to the Châteauguay HVDC back to back interconnection to New York, generation can be radially connected to the New York system through Line 7040. The Variable Frequency Transformer (VFT) at Langlois substation connects into the Cedar Rapids Transmission system, down to New York State at Dennison. The Outaouais HVDC back-to-back converters and accompanying transmission to the Ottawa, Ontario area are now in service. Other ties between Québec and Ontario consist of radial generation and load that can be switched on either system.

Transfer limits between and within some NPCC Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the sub-Area representation for Ontario, New York, and New England are provided in the respective references.

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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. 28

The acronyms and notes used in Figure 2 are defined as follows:

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

### 3.4 Operating Procedures to Mitigate Resource Shortages

Each Area takes defined steps as their reserve levels approach critical levels. These steps consist of load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves. Table 7 summarizes the load relief assumptions modeled for each NPCC Area.

**Table 7: NPCC Operating Procedures - 2019 Summer Load Relief Assumptions (MW)**

<table>
<thead>
<tr>
<th>Actions</th>
<th>QC</th>
<th>MT</th>
<th>NE</th>
<th>NY 29</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Public Appeals</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SCR</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>853</td>
<td>-</td>
</tr>
<tr>
<td>SCR Load / Man. Volt. Red.</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.20%</td>
<td>-</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>500</td>
<td>162</td>
<td>625</td>
<td>655</td>
<td>473</td>
</tr>
<tr>
<td>3. Voltage Reduction</td>
<td>250</td>
<td>-</td>
<td>412</td>
<td>1.11%</td>
<td>-</td>
</tr>
<tr>
<td>Interruptible Load 30</td>
<td>-</td>
<td>329</td>
<td>-</td>
<td>166</td>
<td>790</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>750</td>
<td>505</td>
<td>-</td>
<td>-</td>
<td>945</td>
</tr>
<tr>
<td>Appeals / Curtailments</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>81</td>
<td>-</td>
</tr>
<tr>
<td>5. 5% Voltage Reduction</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2.1%</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>-</td>
<td>-</td>
<td>980</td>
<td>1,310</td>
<td>-</td>
</tr>
<tr>
<td>Appeals / Curtailments</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

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 7 was a reasonable approximation for this reliability assessment.

The need for an Area to begin implementing these Operating Procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified peak load, and as a per unit of the available capacity for the hour.

### 3.5 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. The methodology used is described in Appendix C - Multi-Area Reliability Simulation Program Description - Resource Allocation Among Areas (Section C.3).

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29 Values for New York’s SCR Program has been derated to account for historical availability.

30 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.
3.6 Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the PJM-RTO and MISO (Midcontinent Independent System Operator) was modeled. Their assumptions are summarized in Table 8.

<table>
<thead>
<tr>
<th></th>
<th>PJM</th>
<th>MISO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>153,190</td>
<td>95,432</td>
</tr>
<tr>
<td>Peak Month</td>
<td>July</td>
<td>July</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>189,433</td>
<td>111,772</td>
</tr>
<tr>
<td>Purchase/Sale (MW)</td>
<td>2,259</td>
<td>-3,134</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>30.5</td>
<td>18.3</td>
</tr>
<tr>
<td>Weighted Unit Availability (%)</td>
<td>86.2</td>
<td>82.1</td>
</tr>
<tr>
<td>Operating Reserves (MW)</td>
<td>3,400</td>
<td>3,906</td>
</tr>
<tr>
<td>Curtailable Load (MW)</td>
<td>8,154</td>
<td>4,272</td>
</tr>
<tr>
<td>No 30-min Reserves (MW)</td>
<td>2,765</td>
<td>2,670</td>
</tr>
<tr>
<td>Voltage Reduction (MW)</td>
<td>2,201</td>
<td>2,200</td>
</tr>
<tr>
<td>No 10-min Reserves (MW)</td>
<td>635</td>
<td>1,236</td>
</tr>
<tr>
<td>Appeals (MW)</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (%)</td>
<td>100.0 +/- 4.5, 9.1, 13.6</td>
<td>100.0 +/- 3.7, 7.5, 11.2</td>
</tr>
</tbody>
</table>

Figure 3 shows the 2019 summer Projected Monthly Expected Peak Loads for NPCC, PJM and the MISO for the 2002 Load Shape assumption.

Beginning with the 2015 NPCC Long Range Adequacy Overview, (LRAO) 32 the MISO region (minus the recently integrated Entergy region) was included in the analysis replacing the RFC-OTH and MRO-US regions. In previous versions of the LRAO, RFC-OTH and MRO-US were included to represent specific areas of MISO, however due to difficulties in gathering load and capacity data for these two regions (since most of the reporting is done at the MISO level), it was decided to start including the entirety of the northern MISO region in the model.

MISO was modeled in this study due to the strong transmission ties of the region with the rest of the study system.
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, dated January 2019. Load Forecast Uncertainty was modeled consistent with recent PJM planning 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 that the model is based on, sampling size, and how many years in the future for which the load forecast is being derived.

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 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 and assumptions. All activities of the TEAC can be found at: www.pjm.com. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing within the model, consistent with PJM’s regional Transmission Expansion Plan.

3.7 Study Scenarios

This study evaluated two cases (Base Case and Severe Case); a summary description is provided in Tables 9 and 10.

Table 9: Base Case and Severe Case Assumptions for NPCC Area

<table>
<thead>
<tr>
<th>System</th>
<th>Base Case Assumptions</th>
<th>Severe Case – Additional Constraints</th>
</tr>
</thead>
</table>
| System | - As-Is System for the year 2019  
- Transfers allowed between Areas  
- 2002 Load Shape adjusted to Area’s year 201  
forecast (expected & extreme assumptions) | - Transfer capability between NPCC and the MISO- ‘Other’ reduced by 50%. |
| Maritimes | - ~ 1,150 MW of installed wind generation  
(modeled using April 2011 to March 2012 hourly wind year now including 164 MW of formerly energy only units in Nova Scotia)  
- 110 MW of export contracts assumed  
- 347 MW of demand response (interruptible load) available | - Wind capacity de-rated by half (~575 MW) during July and August due to calm weather  
- Natural gas fueled units de-rated by half (~257 MW) for July and August due to supply disruptions (dual fuel units assumed to revert to oil) |
| New England | - Existing and planned generation resources and load forecast consistent with the 2019 CELT Report  
- Major additions: Canal 3 (~330MW)  
Bridgeport 3 (~510 MW)  
- Major retirement: Pilgrim on 6/1/2019  
- Imports based on 2019/20 3rd Annual Reconfiguration Auction | - Assumed 50% reduction to the import capabilities of external ties  
- Maintenance overrun by 4 weeks |
| New York | - Updated Load Forecast – (NYCA -32,429 MW; NYC - 11,607 MW; LI – 5,279 MW  
- Assumptions consistent with the “New York Installed Capacity Requirements for May 2019 through April 2020” | - Extended Maintenance in southeastern New York (500 MW)  
- 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  
- Gilboa 1 not in-service for the summer period |
| Ontario | - Forecast consistent with the Ontario IESO’s “Reliability Outlook – An Assessment of Ontario’s Electricity System From April 2019 to September 2020” (March 20, 2019)  
- Existing and planned generation resources and demand measures modeled  
- Demand forecast includes pricing, conservation and demand measures  
- Import/export contracts updated as of Q1 2018 | - ~800 MW of maintenance extended into the summer period  
- Hydroelectric capacity and energy 10% lower than the Base Case |
| Québec | - Planned resources and load forecast consistent with the “Québec 2018 NPCC Interim Review of Resource Adequacy” – including ~6,500 MW of scheduled maintenance and restrictions  
- Wind generation derated 100% for the Summer period  
- ~1,600 MW of sales to neighboring areas | - ~1,000 MW of capacity assumed to be unavailable for the summer peak period |
### Table 10: Base Case and Severe Case Assumptions for Neighboring Areas

<table>
<thead>
<tr>
<th></th>
<th>Base Case Assumptions</th>
<th>Severe Case Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PJM-RTO</strong></td>
<td>- As-Is System for the 2019 summer period – based on the PJM 2018 Reserve Requirement Study 37&lt;br&gt;- 2002 Load Shapes and Load Forecast Uncertainty adjusted to the 2019 forecast provided by PJM&lt;br&gt;- Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)</td>
<td>- Load Forecast Uncertainty increased by one percent&lt;br&gt;- Forced Outage rates increased for all units by one percent&lt;br&gt;- ~5,000 MW of additional high ambient temperature generator derates (June-August)&lt;br&gt;- 90% compliance of DR +EE resources</td>
</tr>
<tr>
<td><strong>MISO</strong> 38</td>
<td>- As-Is System for the 2019 summer period – Based on NERC ES&amp;D database, updated by the MISO, compiled by PJM staff&lt;br&gt;- 2002 Load Shapes and Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM&lt;br&gt;- Operating reserve 3,906 MW (30-min. 2,670 MW; 10-min. 1,236 MW)</td>
<td></td>
</tr>
</tbody>
</table>

---


38 Does not include the Entergy region (MISO-South).
4. STUDY RESULTS

4.1 Base Case Scenario

Figure 4 shows the estimated need for the indicated Operating Procedures in days/period for the May through September 2019 period for the expected peak load (probability-weighted average of the seven load levels simulated) for the Base Case. Detailed results from these MARS simulations are provided in Appendix B.

![Figure 4: Estimated Use of Operating Procedure for Summer 2019 Base Case Assumptions - Expected Peak Load Level](image)

Figure 5 shows the corresponding results for the extreme peak load (representing the second to highest load level, having approximately a 6% chance of occurring) for the Base Case. Detailed results from these MARS simulations are also provided in Appendix B.

![Figure 5: Estimated Use of Operating Procedures for Summer 2019 Base Case Assumptions - Extreme Peak Load Level](image)
4.2 Severe Case Scenario

Figure 6 shows the estimated use of Operating Procedures for the NPCC Areas for the expected peak load (probability-weighted average of the seven load levels simulated) for the Severe Case. Detailed results from these MARS simulations are provided in Appendix B.

![Figure 6: Estimated Use of Operating Procedure for Summer 2019 Severe Case Assumptions - Expected Peak Load Level](image)

Figure 7 shows the estimated use of the indicated Operating Procedures for the Severe Case for the extreme peak load level (representing the second to highest load level, having approximately a 6% chance of occurring).

![Figure 7: Estimated Use of Operating Procedure for Summer 2019 Severe Case Assumptions - Extreme Peak Load Level](image)
5. HISTORICAL REVIEW

Table 11 compares NPCC Area’s actual 2018 summer peak demands against the previous forecast assumptions.

Table 11: Comparison of NPCC 2018 Actual and Forecast Summer Peak Loads

<table>
<thead>
<tr>
<th>Area</th>
<th>Date</th>
<th>Actual Peak (MW)</th>
<th>Forecast Peak (MW)</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td>July 5, 2018</td>
<td>21,448</td>
<td>21,449</td>
<td>24,023</td>
<td></td>
<td>May</td>
</tr>
<tr>
<td>Maritimes</td>
<td>May 4, 2018</td>
<td>3,267</td>
<td>3,416</td>
<td>3,730</td>
<td></td>
<td>May</td>
</tr>
<tr>
<td></td>
<td>August 28, 2018</td>
<td>3,243</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>August 29, 2018</td>
<td>25,899 40</td>
<td>28,427 41</td>
<td>32,037 42</td>
<td></td>
<td>August</td>
</tr>
<tr>
<td>New York</td>
<td>August 29, 2018</td>
<td>31,861</td>
<td>32,904</td>
<td>35,714</td>
<td></td>
<td>August</td>
</tr>
<tr>
<td>Ontario</td>
<td>September 5, 2018</td>
<td>23,240</td>
<td>22,002</td>
<td>24,523</td>
<td></td>
<td>July</td>
</tr>
</tbody>
</table>

A summary review of the last summer demand and main operational issues are presented below, while a detailed historical weather review is presented in APPENDIX E.

5.1 Operational Review

Québec

The Québec Area actual internal peak demand for summer 2018 occurred on July 5, 2018 at Hour Ending 18 EDT and was 21,448 MW. The Québec actual internal demand coincident to the NPCC

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39 See: [https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2018_Summer.pdf](https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2018_Summer.pdf).
40 The 25,899 MW was the actual peak occurred on August 29, 2018 at hour ending 17:00. The gross peak was 29,600 MW after the reconstitution for demand resources and Behind-the-Meter PV. The 50/50 weather normalized gross peak is 28,740 MW.
41 25,729 MW Net load forecast after taking into account the reduction from the passive demand resources and the Behind-the-Meter PV.
42 29,329 MW Net load forecast after taking into account the reduction from the passive demand resources and the Behind-the-Meter PV.
peak was 20,512 MW. Transfers to other areas during the NPCC coincident peak were
approximately 5,500 MW (maximum for May).

No resource adequacy events occurred during the 2018 Summer Operating Period.

**Maritimes**
The Maritimes Area load is the mathematical sum of the forecast or actual peak loads of the sub-
areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern

The Maritimes summer peak load was 3,267MW and occurred on May 4, 2018 at hour ending
10:00 am ADT. The Maritime Provinces did not experience any unexpected extreme or adverse
weather conditions; all major transmission lines were in-service.

**New England**
High temperatures at the end of the month led to the region’s highest peak demand in more than
five years on August 29th at 25,944 MW, with 45 MW met through reductions by active demand
resources. The average temperature during August was 75° Fahrenheit (F) in New England,
compared to 70°F recorded as the average during the previous August. The average dewpoint, a
measure of humidity, was 66°F in August 2018, up from 59°F in August 2017. There were 194
cooling degree days (CDD) during August 2018, significantly higher than the 79 CDD seen in
August 2017. The normal number of CDD in August is 102 in New England.

On Monday, September 3rd, due to the hotter-than-forecasted weather and a string of unplanned
generator outages, power system operating reserves ran short in New England. ISO New England
system operators implemented several steps of operating procedure to address the reserve shortage
and recover the required level of operating reserves. The weather forecast for Boston called for a
high temperature of 89° Fahrenheit (F) and a dew point of 70°, but the actual high temperature was
94° and the dew point was 73°. Similarly, for Hartford, the forecasted temperature and dew point
were 90° and 71°, but the actual temperature and dew point came in at 94° and 74°, respectively.

Demand for electricity peaked at about 22,956 MW during the hour from 5 to 6 p.m., about 2,400
MW higher than expected when the day began, based on forecasted weather conditions for the
day. Several power plants also went offline unexpectedly throughout the day. In all, about 1,600
MW of forced generation outages occurred on Monday. Between 3:30 p.m. and 4 p.m., ISO New
England implemented 5 of the 11 actions available in Operating Procedure 4 Action During a
Capacity Deficiency, to address the capacity deficiency.
New York

The actual ambient temperatures were above the 20-year mean in May, July, and August; and near average in June. 19 days over 90F in Albany. The total load (GWh) was above 50/50 projections. The peak load was below the 50/50 projection for the 5th consecutive summer. The Summer 2018 50/50 forecast was 32,904 MW. The 2018 actual summer peak load was 31,861 MW (on August 29th). There were six days with peak loads over 31,000 MW. The 2017 summer actual peak load was 29,677 MW.

June 30 – July 5, 2018

Six-day heat wave crossed much of the Mid-Atlantic, New York, and the Northeast from Saturday, June 30th through Thursday, July 5th with temperatures exceeding 90F all six days with extremely high levels of humidity. Prior to June 30th, the New York ISO worked with the Transmission Owners to reschedule transmission maintenance work. The NYISO participated in conference calls with NPCC and Transmission Owners. Transmission Owners activated local demand response programs during the heatwave. Actual peaks during this time period were reduced by pop-up showers that were not in the forecast. The Wednesday, July 4th holiday may also have had an impact.

August 27 – 29, 2018

A three-day heat wave crossed New York state. On Tuesday, August 28th the peak load was 31,825 MW. The New York ISO activated Zone J Demand Response (481 MW) for New York City transmission security from 12:00 to 18:00. Some New York utilities activated their utility demand response programs (648 MW). External capacity was called upon.

On Wednesday, August 29th, the peak load was 31,861 MW (small pop-up showers in upstate beginning 3 PM). This is the New York Summer 2018 Peak Load. The New York ISO activated Zone J Demand Response (481 MW) for NYC transmission security from 12:00 to 18:00. Some New York utilities activated their utility demand response programs (660 MW). External capacity was called upon.

September 3-6, 2018

On Monday (Labor Day), September 3rd, the peak load was 28,125 MW. New York purchased approximately 250 MW of emergency energy was from the Ontario IESO to facilitate sale of emergency energy to ISO- New England for Hour Beginning 17. On Tuesday, September 4th, the peak load was 31,156 MW. Some New York utilities activated their utility demand response programs (660 MW). External capacity was called upon.


44 See: [https://www.weather.gov/media/aly/Climate/90DegreeDays.pdf](https://www.weather.gov/media/aly/Climate/90DegreeDays.pdf).
programs (28MW). On Wednesday, September 5th, the peak load reached 31,458 MW. Some New York utilities activated their utility demand response programs (262 MW). On Thursday, September 6th, the peak load was 30,609 MW. Some New York utilities activated their utility demand response programs (305MW).

No New York ISO Demand Response nor state-wide capacity commitments were needed September 3rd to 6th.

Ontario
The annual peak occurred for the third consecutive year during a heat wave in September. September’s weather was above normal on average as the month started out hot and humid leading into the Labour Day weekend. Demand peaked on Wednesday, September 5th, the hottest day of the month with temperatures reaching 33.9 °C in Toronto.

6. CONCLUSIONS

Base Case Scenario
All Areas are not expected to use their Operating Procedures designed to mitigate resource shortages (likelihoods of less than 0.5 days/period 45) during the 2019 summer period for the Base Case conditions assuming the expected peak load forecast. The expected peak load level results were based on the probability-weighted average of the seven load levels simulated.

Extreme Peak Load 46
The Maritimes Area shows a likelihood of reducing their 30-min reserve (less than the chance of one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

The New England Area shows a likelihood of reducing their 30-min reserve (less than the chance of one occurrence), and also calling on voltage reduction (less than the chance of one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

The New York Area shows a likelihood of activation of their demand response programs, (less than a chance of two occurrences) and also reducing their 30-min reserve (less than a chance of

45 Likelihoods of less than 0.5 days/period are not considered significant.
46 Represents the second to highest load level, having approximately a 6% chance of occurring.
one occurrence) over the 2019 summer period for the Base Case conditions assuming the extreme peak load forecast.

**Severe Case Scenario**

Only the New York Area shows a likelihood of activation of their demand response programs (chance of two occurrences), and also reducing their 30-min reserve (chance of one occurrence) during the 2019 summer period for the Severe Case conditions assuming the expected peak load forecast. The expected peak load level results were based on the probability-weighted average of the seven load levels simulated.

The New England and New York Areas, and to a lesser extent, the Quebec, Maritimes and Ontario Areas show greater likelihoods of using all their Operating Procedures designed to mitigate resource shortages during the 2019 summer period for the Severe Case conditions assuming the extreme peak load forecast (represents the second to highest load level, having approximately a 6% chance of occurring).
Appendix VIII - CP-8 2019 Summer Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

APPENDIX A

OBJECTIVE, SCOPE OF WORK AND SCHEDULE

A.1 Objective
On a consistent basis, evaluate the near-term seasonal resource 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 2019 - 2020 time period.

A.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 2019 - 2020 time period to consistently review the resource adequacy of NPCC Areas and reflecting neighboring Regions’ assumptions under Base Case (likely available resources and transmission) and Severe Case assumptions for the May to September 2019 summer and November 2019 to March 2020 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 (2019 - 2020) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages.

A.3 Schedule
A report incorporating the results of the probabilistic multi-area summer reliability assessment will be approved no later than April 19, 2019.

A report incorporating the results of the probabilistic multi-area winter reliability assessment will be approved no later than December 3, 2019.
## APPENDIX B

### DETAILLED STUDY RESULTS

### Table 12: Base Case Assumptions - Expected Need for Indicated Operating Procedures (days/period)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Québec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min VR</td>
<td>10-min Appeal/Disc</td>
<td>30-min IL</td>
<td>10-min Appeal/Disc</td>
<td>30-min VR</td>
</tr>
<tr>
<td>May 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.006</td>
<td>0.002</td>
</tr>
<tr>
<td>June 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.008</td>
<td>0.002</td>
</tr>
<tr>
<td>July 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.070</td>
<td>0.026</td>
</tr>
<tr>
<td>Aug 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.014</td>
<td>0.004</td>
</tr>
<tr>
<td>Sep 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.025</td>
<td>0.007</td>
</tr>
<tr>
<td>May-Sep 2002</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.123</td>
<td>0.041</td>
</tr>
</tbody>
</table>

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

Occurrences 0.5 or greater are highlighted.
### Table 13: Severe Case Scenario - Expected Need for Indicated Operating Procedures (days/period)

<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>Apl Disc</td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>May</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>June</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>July</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>Aug</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>Sep</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>May-Sep</td>
<td></td>
<td></td>
<td></td>
<td>30-min</td>
<td>10-min</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>03/04 Load Shape-Expected Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>May</td>
</tr>
<tr>
<td>June</td>
</tr>
<tr>
<td>July</td>
</tr>
<tr>
<td>Aug</td>
</tr>
<tr>
<td>Sep</td>
</tr>
<tr>
<td>May-Sep</td>
</tr>
</tbody>
</table>

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

Occurrences 0.5 or greater are highlighted.
APPENDIX C

MULTI-AREA RELIABILITY 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.

C.1 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.

C.2 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 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

See: https://www.geenergyconsulting.com/practice-area/software-products/mars
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.

C.3 Resource Allocation Among Areas

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

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

C.4 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 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 Unit**

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

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

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

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

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.

**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.

### C.5 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.
C.6 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 the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.
APPENDIX D

MODELING DETAILS

D.1 Resources

Details regarding the NPCC Area’s assumptions for resources are described in the respective Area’s most recent *NPCC Comprehensive Review of Resource Adequacy*. In addition, the NPCC Areas provided the following additional information:

**New England**
The New England generating unit ratings were consistent with their seasonal capability as reported in the 2019 CELT report. Active Demand Capacity Resources and capacity imports are based on their Capacity Supply Obligations of the 3rd annual Reconfiguration Auction of Capacity Commitment Period of 2019-20.

**New York**
The Base Case assumes that the New York City and Long Island localities will meet their respective locational installed capacity requirements as described in the New York ISO Report entitled *Locational Installed Capacity Requirements Study covering the New York Control Area for the 2019 – 2020 Capability Year*, dated January 17, 2019, and that New York State will meet the capacity requirements described in the *New York Control Area Installed Capacity Requirements for the Period May 2019 – April 2020*, New York State Reliability Council, Technical Study Report, dated December 7, 2018.

**Existing Resources**
All in-service New York generation resources were modeled. The New York unit ratings were based on the Dependable Maximum Net Capability (DMNC) values from the *2018 Load & Capacity Data of the NYISO* (Gold Book).

**Ontario**
For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario IESO *Reliability Outlook: An Adequacy*.

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48 See: [https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx](https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx).
Québec
The Planned resources are consistent with the *Québec 2018 NPCC Interim Review of Resource Adequacy*. 54

Maritimes
Resources in the Maritimes Area are winter DMNC ratings de-rated for the summer period.

D.2 Resource Availability

New England
This probabilistic reliability assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon the approved maintenance schedules. Individual generating unit forced outage assumptions were based on the unit’s historical data and North American Reliability Corporation average data for the same class of unit.

New York

Ontario
For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario IESO *Reliability Outlook: An Adequacy Assessment of the Ontario’s Electricity System From April 2019 to September 2020*, dated (March 20, 2019). 57


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


Québec
The planned outages for the summer period are reflected in this assessment. The number of planned outages is consistent with historical values.

Maritimes
Individual generating unit maintenance assumptions are based on approved maintenance schedules for the study period.
D.3 Thermal

New England
The Seasonal Claimed Capability as established through the Claimed Capability Audit, is used to represent the non-intermittent thermal resources. The Seasonal Claimed Capability for intermittent thermal resources is based on their median net real power output during Reliability Hours.

New York
Installed capacity values for thermal units are based on seasonal Dependable Maximum Net Capability (DMNC) test results. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled in the MARS Program using a multi-state representation that represents an equivalent forced outage rate on demand (EFORd). Planned and scheduled maintenance outages are modeled based upon schedules received by the NYISO and adjusted for historical maintenance. A nominal MW value for the summer assessment representing historical maintenance during the summer peak period is also modeled.

Ontario
The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Quebec
For thermal units, Maximum Capacity is defined as the net output a unit can sustain over a two-consecutive hour period.

Maritimes
Combustion turbine capacity for the Maritimes Area is winter DMNC. During the summer, these values are de-rated accordingly.
D.4 Hydro

New England
New England uses the Seasonal Claimed Capability as established through the Claimed Capability Audit to represent the hydro resources. The Seasonal Claimed Capability for intermittent hydro resources is based on their median net real power output during Reliability Hours (14:00 – 18:00).

New York
Large hydro units are modeled as thermal units with a corresponding multi-state representation that represents an equivalent forced outage rate on demand (EFORD). For run of river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run of river unit seasonality is captured by using GE-MARS functionality to randomly select an annual shape for each run of river unit in each draw. Each shape is equally weighted.

Ontario
Hydroelectric resources are modeled in the MARS Program as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data since market opening (2002).

Quebec
For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Maritimes
Hydro in the Maritimes is predominantly run of the river but enough storage is available for full rated capability during daily peak load periods.

D.5 Solar

New England
The majority of solar resource development in New England is the state-sponsored distributed Behind-the-Meter (BTM) PV that does not participate in wholesale markets but reduces the system load observed by ISO New England. The BTM PV are modeled as a load modifier on an hourly basis, based on the 2002 historical hourly weather profile.

New York
New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured
by using GE-MARS functionality to randomly select an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.

Summer capacity values for solar units are based on average production during hours 14:00 to 18:00 for the months of June, July, and August. Winter capacity values for solar units are based on average production during hours 16:00 to 20:00 for the months of December, January, and February.

**Ontario**
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.

**Québec**
In the Québec area, behind-the-meter generation (solar and wind) is estimated at approximately 10 MW and doesn’t affect the load monitored from a network perspective.

**Maritimes**
At this time, solar capacity in the Maritimes is behind the meter and netted against load forecasts. It does not currently count as capacity.

### D.6 Wind

**New England**
New England models the wind resources using the Seasonal Claimed Capability as determined based on their median net real power output during Reliability Hours (14:00 – 18:00).

**New York**
New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by using the-MARS functionality to randomly select an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Summer capacity values for wind units are based on average production during hours 14:00 to 18:00 for the months of June, July, and August. Winter capacity values for wind units are based on average production during hours 16:00 to 20:00 for the months of December, January, and February.

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

Québec
Québec utilizes units of a fixed capacity (that varies seasonally) to represent the expected capacity. The expected capacity at winter peak is 30% of the Installed (Nameplate) capacity, except for a small amount (roughly 3%) which is derated for all years of the study. For the summer period, wind power generation is derated by 100%.

Maritimes
The Maritimes Area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes from the fiscal year of 2011/2012. Each sub-area’s actual MW wind output was normalized by the total installed capacity in the sub-area during that fiscal year. The data is considered typical having had substantially all of the existing Maritimes Area wind resources by that time and no major outages due to icing or other abnormal weather or operating problems. These profiles, when multiplied by current sub-area total installed wind capacities yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts is the Maritimes Area’s hourly wind forecast.

D.7 Demand Response

New England
The passive non-dispatchable demand resources, On-Peak and Seasonal-Peak, are expected to provide ~2,912 MW of load relief during the peak hours. About 493 MW of active demand capacity resources participate in the ISO New England capacity market and are offered into the energy market on a daily basis and dispatched according to price. 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.

New York
The Installed Capacity (ICAP) Special Case Resource program allows demand resources that meet certification requirements to offer Unforced Capacity (“UCAP”) to Load Serving Entities. 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, which serve as the interface between the NYISO and the resources. Responsible Interface Parties also act as aggregators of SCRs. SCRs that have sold ICAP are obligated to reduce their system load when called upon by the New York ISO 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 Responsible Interface Party in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the New York ISO 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, Responsible Interface Parties are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

SCRs are modeled as an Operating Procedure step activated to minimize the probability of customer load disconnection. The MARS program models the New York ISO operations practice of only activating operating procedures in zones from which are capable of being delivered.

For this study, 1,309 MW of SCRs were modeled. At the time of the summer peak, this amount was discounted to 903 MW based on historical availability.

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 for energy consumption curtailments provided when the New York ISO calls on the resource. Resources must be enrolled through Curtailment Service Providers, which serve as the interface between the New York ISO 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 EDRP was not modelled in this assessment; currently there are only 6 MW of registered under EDRP, with an estimated net impact of 1 MW.

**Ontario**
The demand measures assumed a total of 790 MW for the summer period.

**Quebec**
No demand response is expected for the summer period.

**Maritimes**
Demand Response in the Maritimes Area is currently comprised of contracted interruptible loads.
E.1 Weather

Highlights - (June - August 2018)  

During June-August, 2018 the average temperature for the Lower 48 states was 73.5°F, 2.1°F above average, tying with 1934 as the fourth warmest summer on record.

Above-average summer temperatures spanned most of the nation, with only one state having near-average June-August temperatures. Twenty-three states across the West, South and Northeast had much-above-average summer temperatures. This included Rhode Island and Utah, which were record warm.

The contiguous U.S. average maximum (daytime) temperature during summer was 86.1°F, 1.8°F above the 20th century average, ranking as the 11th warmest on record. Much-above-average maximum temperatures were observed across the West, Southern Plains and Northeast. Near-average conditions were observed for the Central Plains, Midwest, Southeast, and Mid-Atlantic.

The nationally averaged minimum temperature (overnight lows) was exceptionally warm during summer at 60.9°F, 2.5°F above average and 0.1°F warmer than the previous record set in 2016. Every state had an above-average summer minimum temperature with five states record warm. In general, since records began in 1895, summer overnight low temperatures are warming at a rate nearly twice as fast as afternoon high temperatures for the U.S. and the 10 warmest summer minimum temperatures have all occurred since 2002.

Based on NOAA's Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during August was 125 percent above average and was the fourth highest value on record.

Based on NOAA's Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during August was 125 percent above average and was the fourth highest value on record.

58 See: [https://www.ncdc.noaa.gov/sotc/national/201808](https://www.ncdc.noaa.gov/sotc/national/201808).
Northeast Region

June

The average temperature for the Northeast for the month of June was 64.8 degrees F (18.2 degrees C), which was 0.4 degrees F (0.2 degrees C) below normal. All twelve states within the region experienced average temperatures that were near normal. Departures from normal ranged from 1.8 degrees F (1 degree C) below normal in Maine to 1.6 degrees F (0.9 degrees C) above normal in West Virginia. Vermont, Rhode Island, Maine, New Hampshire, Connecticut, Massachusetts, and New York all experienced average temperatures during the month of June that were below normal. New Jersey recorded an average temperature near normal for June, while Pennsylvania, West Virginia, Maryland, and Delaware each experienced above-normal average temperatures for the month.

Dryness expanded throughout the month in New England. The U.S. Drought Monitor at the beginning of June listed New Hampshire as the only state in the Northeast that was abnormally dry. By the end of the month, 30 percent of the Northeast was abnormally dry, with moderate drought impacting six percent of the region, in the southern parts of Vermont, New Hampshire, and Maine.

Areas in northern Maine experienced unseasonably late frosts and cooler-than-normal temperatures during the first half of June, impacting gardeners and farmers in the areas. Crop damage and late germination resulted from the pockets of frost throughout June in northern New England. Severe weather on June 13th spawned two EF-2 tornadoes in Pennsylvania. A water ban in Northampton, Massachusetts came into effect starting June 15th as a result of the increasingly dry conditions throughout the area. This also prompted over 75 Public Water Suppliers to enforce varying degrees of water bans in other locations throughout Massachusetts. Severe weather moved through much of the Northeast on June 18th, and strong winds caused over 60,000 people in New Hampshire to lose power. An EF-0 tornado briefly touched down in Lincoln, New Hampshire as severe thunderstorms moved through the area that same day. Also, on that day, a microburst created a path of damage that was over a mile long in Waitsfield, Vermont and brought wind gusts up to 80 mph (35.8 m/s), which downed dozens of trees and caused over 16,000 customers to lose power in the area.

July

The average temperature for the Northeast for the month of July was 71.7 degrees F (22.1 degrees C), ranking this as the 14th warmest July on record for the region, with a departure of 2.1 degrees F (1.2 degrees C) above normal. Each state in the region experienced average temperatures that were above normal for July. Eight of the twelve states in the Northeast ranked this July among their 20 warmest on record: Maine, fourth warmest; Massachusetts, New Hampshire, and Vermont, fifth warmest; Rhode Island, eighth warmest; Connecticut, ninth warmest; New York, 10th warmest; and New Jersey, 16th warmest. Temperature departures from normal ranged from 0.3 degrees F (0.2 degrees C) above normal in Maryland to 3.1 degrees F (1.7 degrees C) above normal in Maine, New Hampshire, Vermont, and Massachusetts.

Precipitation varied greatly throughout the region during the month of July. The Northeast received 5.44 inches (138.2 mm) of precipitation on average, which made this the 11th wettest July on record for the region. Connecticut ranked this as their 14th wettest July after receiving 135 percent of normal precipitation. Three states in the region experienced a drier-than-normal July, including Maine, Vermont, and Rhode Island. Precipitation departures from normal ranged from 1.32 inches (33.5 mm) below normal in Rhode Island to 4.58 inches (116.3 mm) above normal in Maryland.

At the beginning of the month, 25 percent of the Northeast was abnormally dry, which included central New York and New England. Moderate drought was impacting six percent of the region in southern Vermont, New Hampshire, and Maine. By the middle of July, 12 percent of the Northeast was experiencing moderate drought conditions. During that time, 30 percent of the region was abnormally dry, and abnormal dryness spread briefly into southern New Jersey and part of the Mid Atlantic. Compared to the beginning of the month, conditions improved by the end of July, when 18 percent of the entire Northeast was abnormally dry and nine percent of the region was in moderate drought.

A heat wave impacted the Northeast at the beginning of July and heavy rain during the second half of the month led to significant flooding in the southern part of the region. From July 1st through July 4th, high humidity along with unusually warm temperatures throughout the region, resulted in heat indices over 110 degrees F (43.3 degrees C) in some areas, prompting Excessive Heat Warnings to be issued by the National Weather Service. Daily high temperature records were set

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at numerous locations throughout New York, Vermont, and Maine. Burlington, Vermont experienced its warmest three-day stretch on record from June 30 through July 2. Two heat-related deaths were reported in New York, along with one in Pennsylvania. On July 10th, severe weather produced hail up to one inch in diameter in Maine, denting cars and windows. Wind damage and fallen trees were also reported that day in parts of Maine and New Hampshire. An EF-0 tornado touched down briefly in Windham County, Connecticut on July 17 with winds up to 85 mph (40 m/s), uprooting numerous trees. Severe weather moved through Massachusetts on that same day and caused lightning strikes that resulted in three house fires. Heavy rain during the second half of the month led to flooding in many states in the southern part of the region in particular. On July 24th, many parts of New England received heavy rain, with much of western Massachusetts receiving over three inches (76.2 mm) of rain, which led to minor street flooding in some areas. In parts of northern New England, many farmers have been impacted by dry conditions.

August

The Northeast experienced its second warmest August on record with an average temperature of 71.5 degrees F (21.9 degrees C), which was 3.3 degrees F (1.8 degrees C) above normal. All twelve states in the region recorded average temperatures this month that were above normal. New Hampshire, Massachusetts, Rhode Island, Connecticut, and Delaware each experienced a record-warm August, while Maine, Vermont, and New Jersey all had their second warmest August on record. Maryland experienced its third warmest August, followed by New York with its fourth warmest, and Pennsylvania recording its sixth warmest on record. Temperature departures for the month ranged from 4.7 degrees F (2.6 degrees C) above normal in Rhode Island to 1.4 degrees F (0.8 degrees C) above normal in West Virginia. This summer was also warmer than normal for all twelve states in the Northeast. With an average temperature of 69.3 degrees F (20.7 degrees C) for the region, this was the sixth warmest summer on record for the Northeast. Rhode Island experienced its warmest summer on record, with a temperature departure of 2.3 degrees F (1.3 degrees C) above normal for the season. Each state ranked this summer among their twenty warmest on record: Massachusetts, third warmest; Connecticut, New Jersey, Maine, New Hampshire, and Vermont, fifth warmest; Delaware and New York, sixth warmest; Maryland, 13th warmest; Pennsylvania, 16th warmest; and West Virginia, 18th warmest.

The Northeast received 5.27 inches (133.9 mm) of precipitation on average this month, which was 135 percent of normal, ranking this as the 11th wettest August on record for the region. On average, Maine and Vermont were slightly drier than normal, but the other states in the region recorded a wetter-than-normal August. It was the tenth wettest for New York, followed by the 11th wettest

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for Massachusetts, New Hampshire, and West Virginia. With an average of 15.06 inches (382.5 mm) of precipitation recorded for the region, this was the eighth wettest summer on record for the Northeast.

Dry conditions improved across the Northeast as the month progressed. At the beginning of August, dry conditions were largely present in northern New York and New England. Abnormal dryness was impacting 18 percent of the Northeast, and 10 percent of the region was in moderate drought. Abnormal dryness eased in much of New Hampshire and southern Maine throughout the course of the month. By the end of August, 13 percent of the Northeast was abnormally dry and seven percent of the region was experiencing moderate drought.

Heavy rain led to flooding in parts of Pennsylvania, New York, and New Jersey throughout this month. On August 2nd, an EF-0 tornado touched down in Queens, New York, damaging a few homes and downing trees and power lines in its short path, but no injuries were reported. Severe weather moved through New England a few days later on August 4th, resulting in minor damage from an EF-0 tornado that moved through in Windham County, Connecticut. Later that same day, an EF-1 tornado in Webster, Massachusetts led to structural damage downtown and displaced about 30 residents from their homes. These storms caused more than 9,000 customers to lose power. A line of strong thunderstorms moved across Long Island, New York on the night of August 7. Fallen trees damaged homes in Selden, New York and house fires were reported from lightning strikes associated with these powerful storms. Railroad services were suspended across parts of Long Island and more than 10,000 customers were without power that night. On August 13th, Lakewood, New Jersey received 8.01 inches (203.5 mm) of rain, which led to the evacuation of over 100 homes in the Ocean County, New Jersey as flash flooding impacted the area. In Seneca County, New York, a similar sequence of events occurred during that same time frame. Hector, New York recorded 6.38 inches (162.1 mm) of rain from August 13th to 14th and then received another 5.15 inches (130.8 mm) during a 24-hour stretch ending August 15th. Road closures were reported along coastal New Jersey and in southern New York that same week as rivers started to overflow their banks, prompting a state of emergency to be issued in many of those areas.

September 62

The Northeast had its third warmest September since 1895. The average temperature was 65.3 degrees F (18.5 degrees C), 4.6 degrees F (2.6 degrees C) above normal. Delaware, Maryland, and West Virginia had a record warm September. Pennsylvania had its second warmest September

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since recordkeeping began, while Massachusetts, New Jersey, New York, Rhode Island, and Vermont had their third warmest. Connecticut and New Hampshire recorded their fourth warmest September on record, while Maine ranked this September as its 12th warmest. Temperature departures ranged from 2.4 degrees F (1.3 degrees C) above normal in Maine to 6.2 degrees F (3.4 degrees C) above normal in West Virginia. Elkins, West Virginia, and Atlantic City, New Jersey, had their warmest September on record, while Erie, Pennsylvania, had its greatest number of September days with a high of at least 90 degrees F (32 degrees C).

September 2018 was the fourth wettest September on record for the Northeast. The region received 6.48 inches (164.59 mm) of rainfall, 165 percent of normal. West Virginia had a record wet September, and eight additional states ranked this September among their twenty wettest on record: Pennsylvania, third wettest; Maryland and Rhode Island, fourth wettest; Connecticut and New Jersey, sixth wettest; Massachusetts, eighth wettest; Delaware, 11th wettest; and New York, 20th wettest. Vermont and Maine were the only two drier-than-normal states. Precipitation for all states ranged from 79 percent of normal in Maine to 271 percent of normal in West Virginia. Five major climate sites had a record wet September: Huntington, Charleston, and Beckley in West Virginia; Atlantic City, New Jersey; and Bridgeport, Connecticut.

The U.S. Drought Monitor released on September 6 showed 8% of the Northeast in a severe or moderate drought and 13% of the region as abnormally dry. These areas included northern and western New York, much of Vermont, parts of New Hampshire, portions of Maine, southeastern Massachusetts, and southern Rhode Island. Much-needed rain during the month improved conditions slightly in many of these areas, with the exceptions being eastern Maine and east of Lake Ontario in New York as abnormal dryness expanded. The U.S. Drought Monitor released on September 27th showed 5% of the Northeast in a severe or moderate drought and 16% of the region as abnormally dry.

Up to 9.50 inches (241.30 mm) of rain fell from September 8th to 10th in western and southern parts of the Northeast. This resulted in flooding, which led to numerous closed roads, some flooded basements, and several water rescues. From September 17th to 18th, the remnants of Florence brought more heavy rain to the region. Rain totals were generally up to 6 inches (152 mm). The rain led to flooded roads, bridges, and homes, as well as water rescues and some evacuations. Thunderstorms produced wind gusts of up to 70 mph (31 m/s) that caused mostly tree damage on September 6 in eastern Maine and on September 21 in western New York.