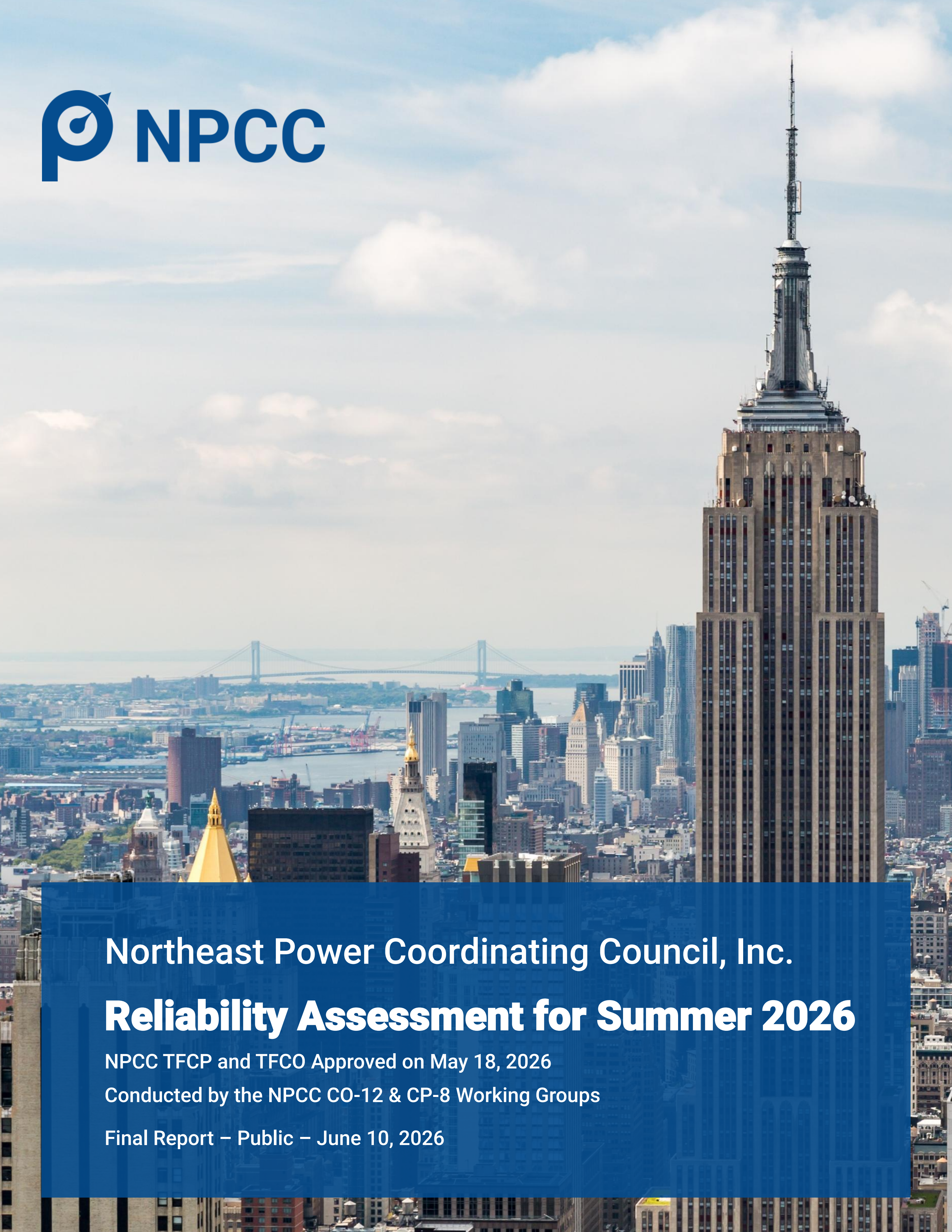

NPCC

Northeast Power Coordinating Council, Inc.

Reliability Assessment for Summer 2026

NPCC TFCP and TFCO Approved on May 18, 2026

Conducted by the NPCC CO-12 & CP-8 Working Groups

Final Report – Public – June 10, 2026

THE INFORMATION IN THIS REPORT IS PROVIDED BY THE CO-12 OPERATIONS PLANNING WORKING GROUP OF THE NPCC TASK FORCE ON COORDINATION OF OPERATION (TFCO) AND THE CP-8 WORKING GROUP OF THE TASK FORCE ON COORDINATION OF PLANNING (TFCP).

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Foreword

The Champlain Hudson Power Express (CHPE) is a 1,250 MW High-Voltage Direct Current (HVDC) transmission project designed to deliver renewable hydropower from Québec directly to New York City. As of mid-May, the project was in its final testing phase and did not have an announced commercial in-service date. The deterministic analysis of this assessment assumed its availability starting the week of July 5, 2026. However, the New York ISO margins exclude the capacity from CHPE since the project was still in testing phase. The probabilistic analysis assumed its availability for the entire summer assessment period.

The New England Clean Energy Connect (NECEC) is a 1,200 MW HVDC tie between Québec and New England and was not modeled in this assessment since it is not supported by a firm capacity supply contract.

1. Executive Summary

This report focuses on the assessment of reliability within the Northeast Power Coordinating Council, Inc. (NPCC) for the 2026 Summer Operating Period[1] and is based on the work of the NPCC CO-12 Operations Planning Working Group and the NPCC CP-8 Working Group on the Review of Resource and Transmission Adequacy. This assessment is based on estimates of demand, resource, and transmission project's availability reported for the summer period, as of May 1, 2026, and can serve as the basis to bracket plausible supply, demand, and operational impacts.

The results of the studies performed by the CO-12 (deterministic) and CP-8 (probabilistic) Working Groups indicate that while New York and New England Areas show a likelihood of relying on non-firm imports this summer, the NPCC Region as a whole maintains sufficient electricity supply to meet summer 2026 demand.

The NPCC CP-8 Working Group on the Review of Resource and Transmission Adequacy provides a seasonal multi-area probabilistic reliability assessment. Additional results of this assessment are included later in this report (Chapter 9) and supporting documentation is provided in **Appendix VIII**.

The probabilistic analysis performed by the CP-8 Working Group estimated the use of established NPCC Area operating procedures during the Summer of 2026. The results of this analysis indicated that under Base Case conditions, NPCC Areas are unlikely to face resource shortages exceeding a cumulative likelihood greater than 0.5 days per period[2] of needing to implement their operating procedures for the expected (50/50) peak load forecast (representing the probability weighted average of all seven load levels modeled). The Maritimes, New England, and New York showed a likelihood of relying on non-firm imports to meet peak demands. However, under the higher peak load levels, the results show a cumulative likelihood greater than 0.5 days per period that the Maritimes, New England, and New York will need to rely on operating procedures in addition to imports to address resource shortages. The higher peak load levels have approximately a 7% chance of occurrence.

The probabilistic assessment suggests that operators in New York and New England will likely need to implement emergency operating procedures and/or Energy Emergency Alerts (EEAs) during periods of higher-than-expected demand and low-likelihood reduced resource conditions with the greatest risks occurring in July and August, demonstrating concerns under extreme conditions. Strategies and procedures are in place to manage potential operational challenges and emergencies as they arise. Because the resource and transmission assessments in this report represent a snapshot in time, market conditions and

1 For this report, the Summer Operating Period evaluation will include operating conditions from week beginning May 3, 2026, through the week beginning September 20, 2026.
2 Likelihoods of less than 0.5 days/period is not considered significant.

reliability margins may change rapidly. Continued vigilance is essential to track any changes in underlying assumptions that could affect the report's findings.

The deterministic analysis performed by the CO-12 Working Group estimated that the forecasted coincident peak demand of 105,062 MW for NPCC occurs during the peak week (week beginning July 12, 2026)[3] with a forecasted net margin of 8,292 MW. This equates to a net margin of 7.9%. Unless otherwise noted, all forecasted demands are 50/50 net peak forecasts. The minimum forecasted NPCC net margin of 6,734 MW (or 6.5%) is expected to occur during the week beginning August 23, 2026. This is an increase from last year, which can mainly be attributed to increases in available installed capacity and a lack of bottled resources expected during this Summer Operating Period.

The Maritimes Area has forecasted a 2026 summer peak demand of 3,691 MW for the week beginning September 20, 2026, with a projected net margin of 1,279 MW (35%). The Maritimes expects to have sufficient resources, with some expectations of imports for elevated peak load conditions, for the duration of summer 2026 with the smallest net margins of 2.5% and -3.6% for the respective 50/50 and 90/10 cases during the week beginning May 24, 2026.

The New England Area expects to have sufficient resources utilizing non-firm imports to meet the 2026 summer peak demand forecast of 25,228 MW. The New England peak is expected for the weeks beginning May 31 through week beginning September 13, 2026,[4] with the lowest projected net margin of -972 MW (-3.9%) during the week of July 5, 2026. This net margin assumes a Net Interchange of 409 MW, which is capacity backed. While the lowest projected net margin is -972 MW when counting only firm capacity, ISO-NE typically imports around 3,000 MW[5] during summer peak load conditions, further supported by the New England Clean Energy Connect (NECEC),[6] which has the capability to import up to 1,200 MW of power into New England from Québec. This capability is not supported by firm capacity supply contracts; it is excluded from the firm capacity totals in this report. NECEC will be used as an "import-only" tie for New England. The 2026 summer demand forecast considers the demand reductions associated with load management, behind-the-meter photovoltaic (BTM PV) systems, and distributed generation.

The New York Area anticipates adequate resources to meet demand for the 2026 Summer Operating Period. The 2026 summer peak forecast is 31,578 MW and anticipated net margins for the expected summer peak period (week beginning June 14 through September 6) are at a minimum of -500 MW (-1.6%). Additionally, Champlain Hudson Power Express (CHPE), a new HVDC interconnection from the Québec area to New York City is expected to be placed

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3 Load and Capacity Forecast Summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in **Appendix I**.

4 New England utilizes a Peak Load Exposure (PLE), which covers operating periods from May 31, 2026, through September 13, 2026. 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(s).

5 See: NPCC 2025 Review of Interconnection Assistance.

6 The official commercial operation date for the New England Clean Energy Connect was January 16, 2026.

in-service this Summer. NYISO's summer resource availability includes the Danskammer, Gowanus, and Narrows units while excluding capacity from CHPE for this assessment since the project was in its final testing phase without a finalized commercial operation date.

The forecasted 2026 Ontario summer peak demand is 22,610 MW for 50/50 weather and 24,799 MW for 90/10 weather during the weeks beginning July 19, 2026, and July 12, 2026, respectively. The anticipated 50/50 and 90/10 margins are also expected during these weeks and are 9.4% and -5.4% respectively. Ontario does not anticipate adequacy concerns under 50/50 conditions and expects to be adequate for 90/10 conditions with outage management, the availability of imports or other operating control actions.

The Québec Area forecasted summer peak demand is 22,490 MW during the week beginning August 2, 2026, with a forecasted net margin of 2,204 MW (9.8%). No resource adequacy problems are forecasted, and the Québec Area expects to be able to assist other areas, if needed. As mentioned previously, there is a new interconnection with New England, NECEC, and one expected with New York during the 2026 Summer Operating Period, CHPE. NECEC is not modeled in this analysis due to its not being supported by any firm capacity contracts. In this analysis, Québec includes 1,250 MW of capacity export to New York via CHPE starting in the week of July 5, 2026.

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 2026 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 additions and revisions.
- Reflected the results of the NPCC CP-8 Working Group's probabilistic assessment[7] of the implementation of operating procedures for the 2026 Summer Operating Period.
- 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 50/50, 90/10 and Above 90/10 system load forecasts, while accounting for assumed resource outages, derates and 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.
- 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[8] (RAS) 2026 Summer Reliability Assessment (NERC SRA).

7 The CP-8 WG assessment conclusions are included in this report as Chapter 9 and **Appendix IX**.
8 Reliability Assessment Subcommittee (RAS) (nerc.com).

3. Demand Forecasts for Summer 2026

The coincident peak demand of 105,062 MW is expected during the week beginning July 12, 2026. For reference, the all-time NPCC coincident peak demand for summer was 112,384 MW on August 1, 2006. The all-time NPCC coincident peak demand was 112,552 on February 3, 2023. Demand and Capacity forecast summaries for the NPCC Region, 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.**

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 because 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. Based on the extent and duration of the weather system, there is the potential for the Québec and Ontario peak demand to be coincident with New England and New York as well. It should also be noted that the non-coincident peak demand calculation is impacted primarily by the fact that Maritimes and Québec can experience late spring demands, influenced by heating loads that occur during the defined Summer Operating Period. In recent years though, Québec's summer peak has contributed to the coincident peak.

The impact of ambient weather conditions on load forecasts can be demonstrated by various means.

- The Maritimes and Ontario represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load.

- ISO New England updates the load forecast for the New England Area 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.

- NYISO uses a weather index that relates air temperature and humidity to the load response and increases the load by a MW factor for each degree above the base value.

- Hydro-Québec, the Québec system operator, updates Area 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 most of the peak demands appear to be confined to the operating weeks in late June through August, each Area is aware that reduced margins could occur during any week of the operating period because 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 the NPCC Area Reliability Coordinator summer forecasts. The historical peak demands for each week are indicated by the "Historical Peak Load" markers on the corresponding figures.

Summary of NPCC Area Forecasts

Maritimes

	Summer 2026 Forecasted Peak: week beginning Sept 20, 2026	Summer 2025 Forecasted Peak: week beginning Sept 21, 2025	Summer 2025 Actual Peak: August 11, 2025, at HE 17 EDT
50/50	3,691	3,584	3,528
90/10	3,929	3,811	
Above 90/10	4,039	3,929	

Table 3-1: Maritimes Area Forecasts (MW)

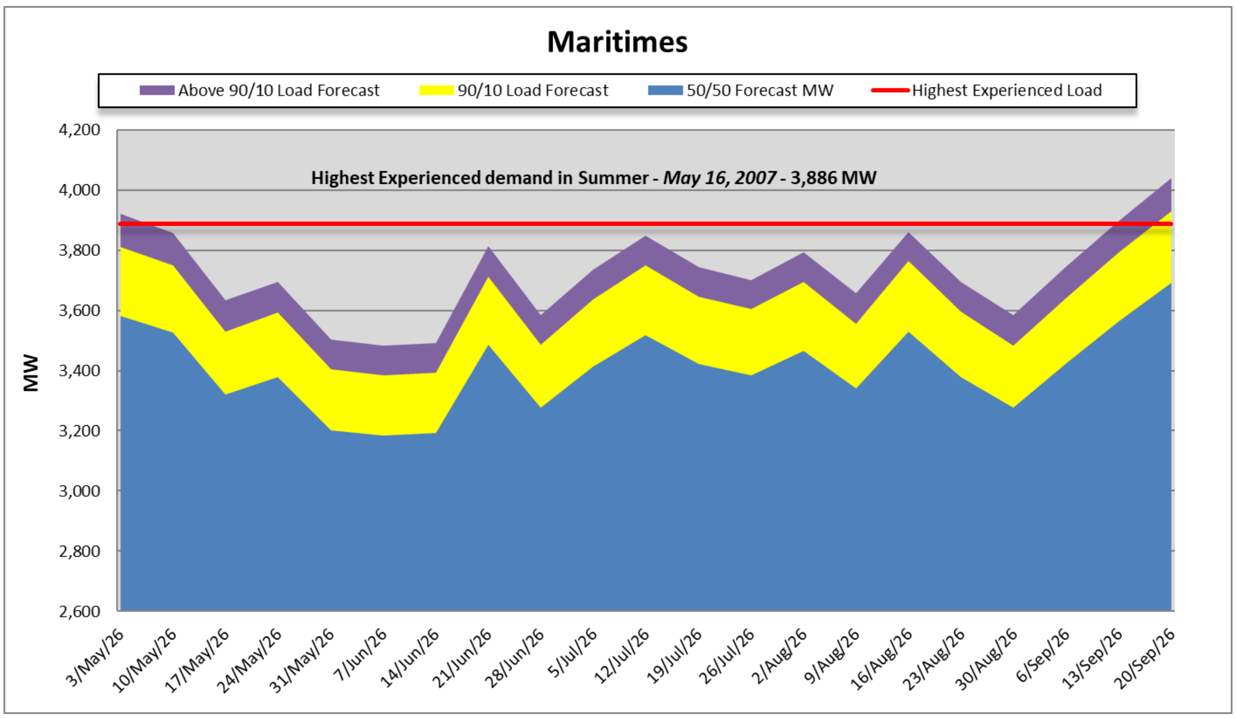

Figure 3-1 Maritimes Summer 2026 Weekly Demand Profile[9]

9 The highest-ever experienced load in the Maritimes Area occurred when there was larger industrial load on the system as well as heating load from cooler weather.

New England

	Summer 2026 Forecasted Peak: weeks beginning May 31 through September 13, 2026[10]	Summer 2025 Forecasted Peak: week beginning June 1 through September 14, 2025	Summer 2025 Actual Peak: June 24, 2025, at HE 19 EDT
50/50	25,228	24,803	26,024[11]
90/10	26,473	25,886	
Above 90/10	26,946	26,752	

Table 3-2: New England Area Forecasts (MW)

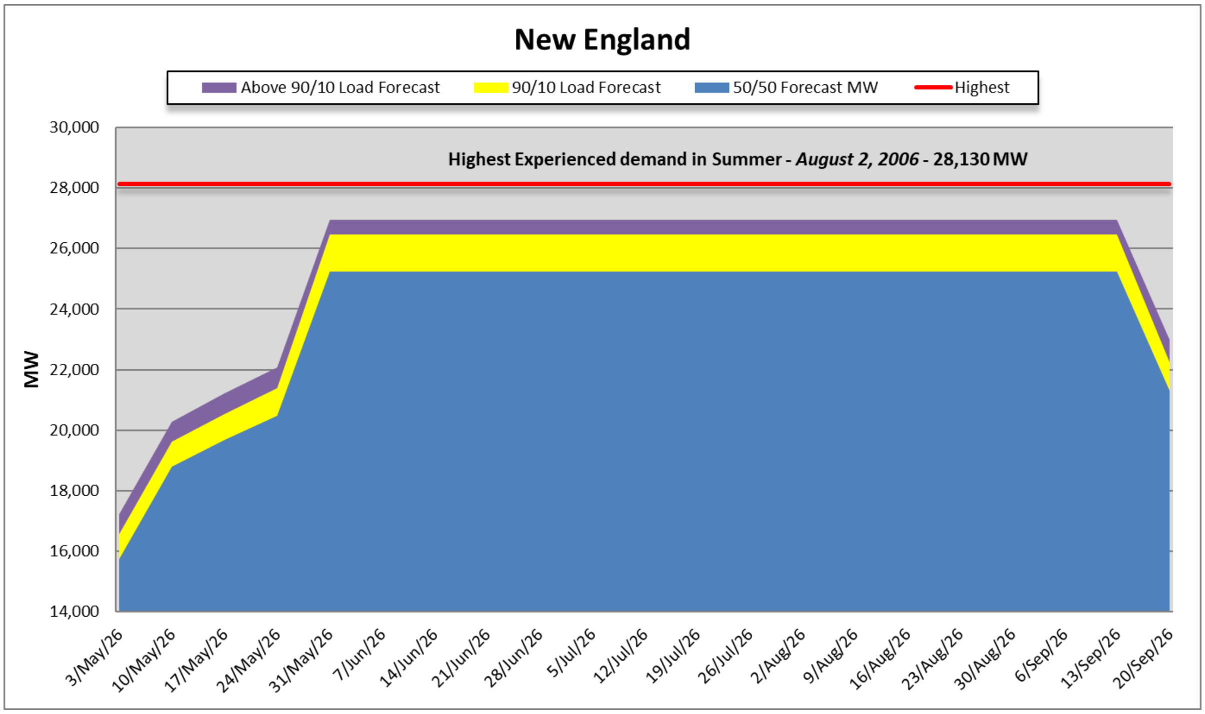

Figure 3-2: New England Summer 2026 Weekly Demand Profile

10 The summer Peak Load Exposure (PLE) period covers the months of June through September 13; and was developed to help mitigate the effects of abnormal weather during the scheduling of generator outages and help forecast conservative operable capacity margins.
11 New England Actual Peak does not account for load served by Settlement Only Generators.

New York

	Summer 2026 Forecasted Peak: weeks beginning June 14 through September 6, 2026	Summer 2025 Forecasted Peak: weeks beginning June 15 through September 7, 2025	Summer 2025 Actual Peak: June 24, 2025, at HE 18 EDT
50/50	31,578	31,471	31,857
90/10	33,343	33,233	
Above 90/10	34,834	34,717	

Table 3-3: New York Area Forecasts (MW)

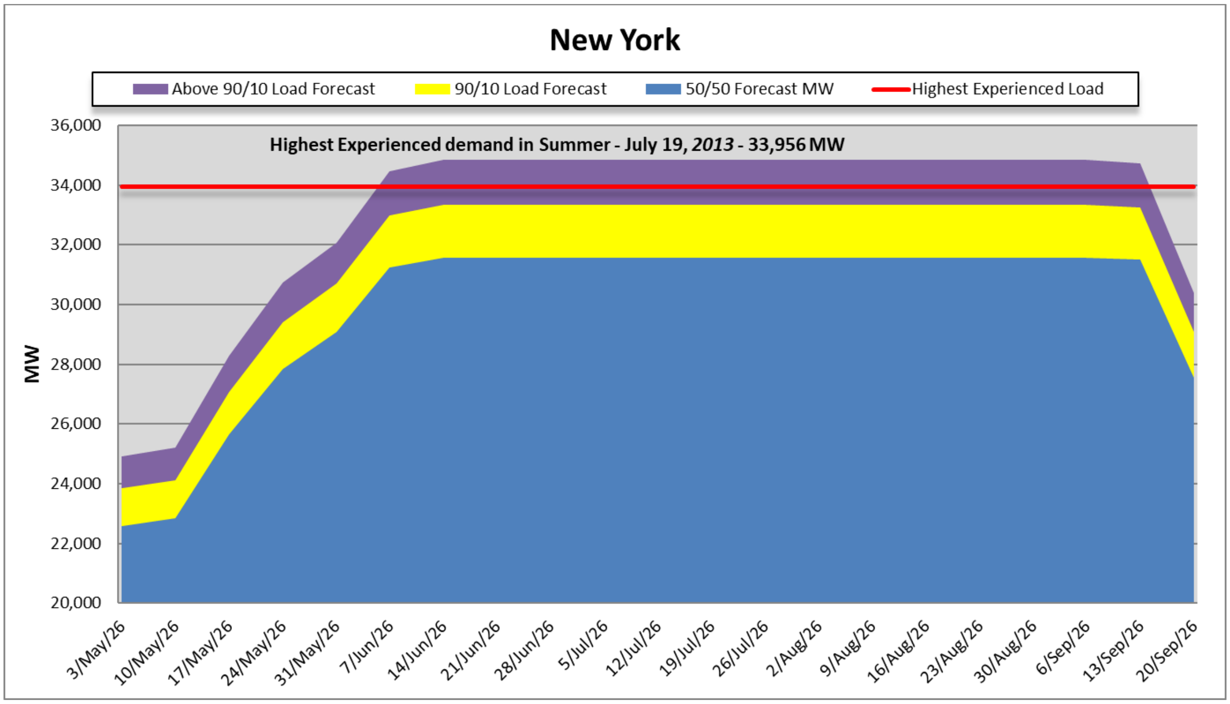

Figure 3-3: New York Summer 2026 Weekly Demand Profile[12]

12 The New York Area's expected Above 90/10 load forecast for the summer exceeds the highest-ever experienced demand from July 19, 2013.

Ontario

	Summer 2026 Forecasted Peak: week beginning July 12 through July 19, 2026	Summer 2025 Forecasted Peak: week beginning July 14, 2025	Summer 2025 Actual Peak: June 24, 2025, at HE 19 EDT
50/50	22,610	21,955	24,862
90/10	24,799	24,231	
Above 90/10	27,291	25,162	

Table 3-4: Ontario Area Forecasts (MW)

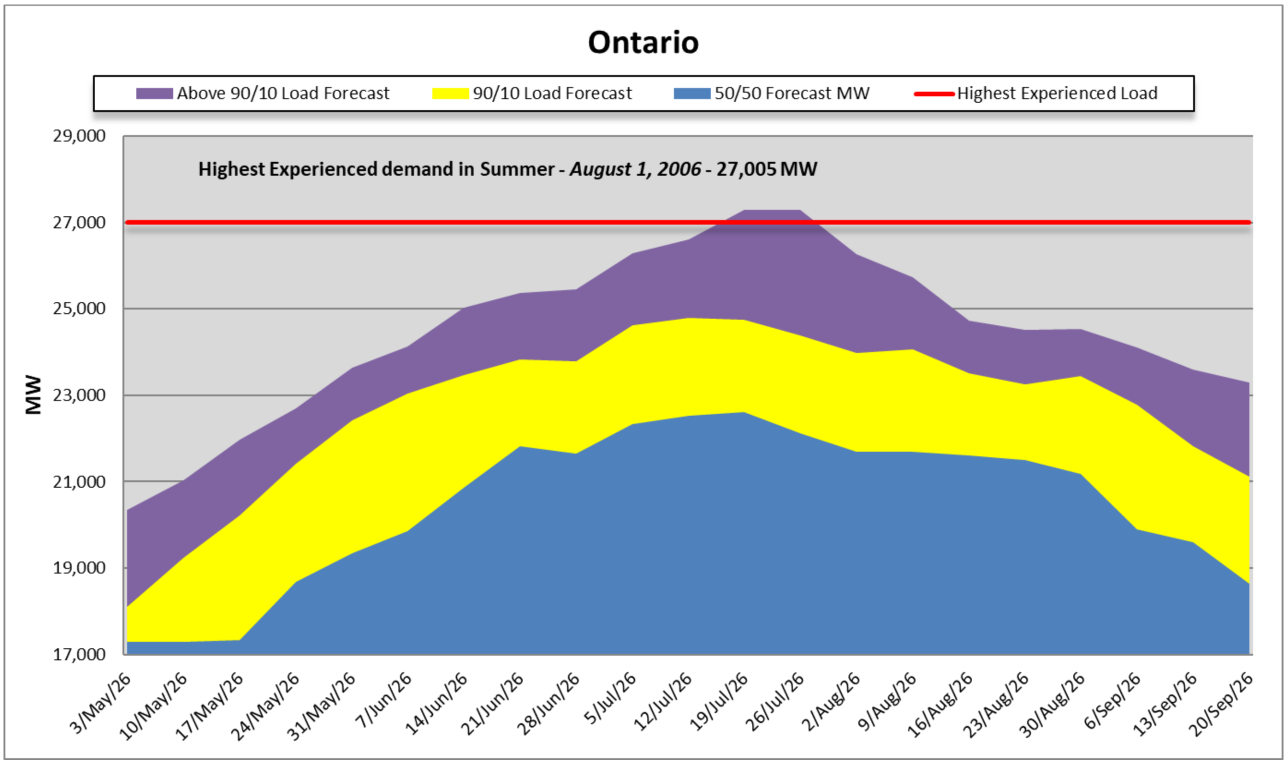

Figure 3-4: Ontario Summer 2026 Weekly Demand Profile[13]

13 The highest-ever actual experienced load in the Ontario Area is beyond the expected 90/10 forecast yet within the expected Above 90/10 forecast for the summer.

Québec

	Summer 2026 Forecasted Peak: week beginning August 2, 2026	Summer 2025 Forecasted Peak: week beginning August 3, 2025	Summer 2025 Actual Peak: August 11, 2025, at HE 18 EDT[14]
50/50	22,490	23,283	22,962
90/10	23,532	24,279	
Above 90/10	23,691	24,662	

Table 3-5: Québec Area Forecasts (MW)

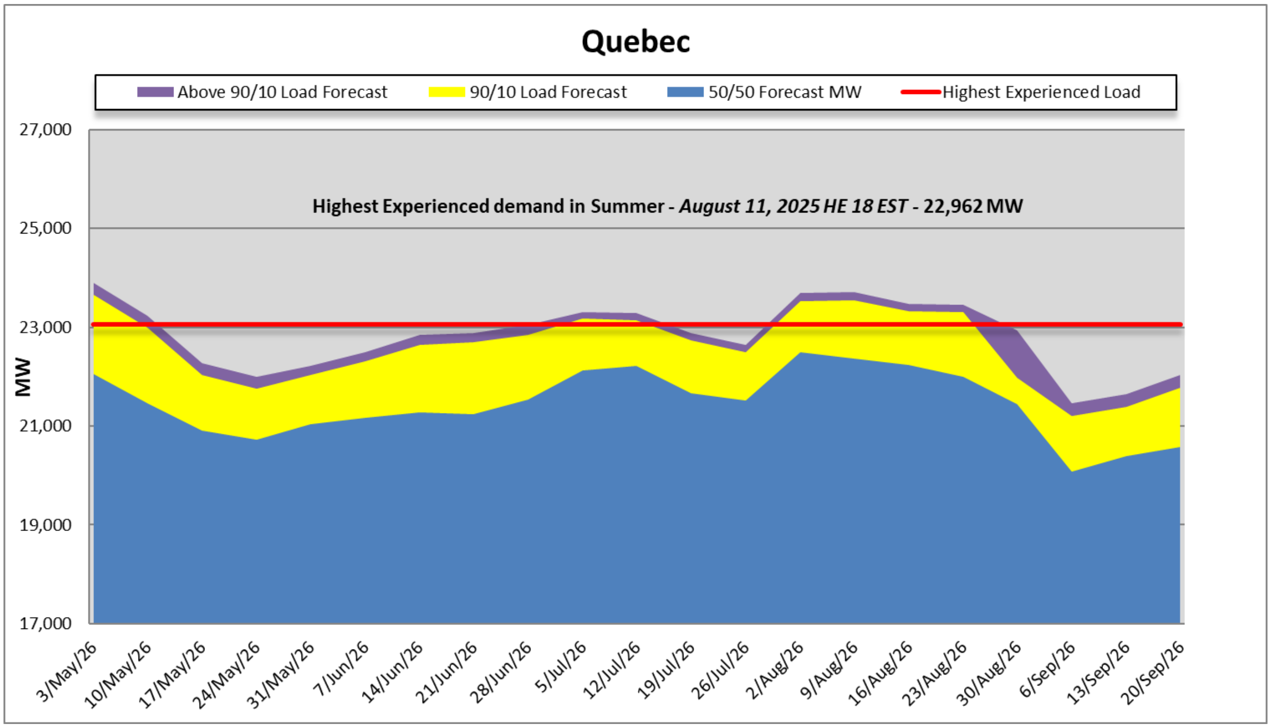

Figure 3-5: Québec Summer 2026 Weekly Demand Profile

14 This represents the third consecutive summer of Québec setting a new summer peak. This summer's 90/10 forecast exceeds last summer's new peak.

4. Resource Adequacy

NPCC Summer 2026 Summary

The assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning July 12, 2026 (105,062 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 (50/50) load and capacity summary for the 2026 Summer Operating Period. **Appendix I**, **Tables AP-2** through **AP-6** contain the 50/50 load forecast and capacity summary for each NPCC Reliability Coordinator Area.

Each entry within **Table 4-1** below is the aggregate of the corresponding entry for the five NPCC Reliability Coordinators. It summarizes the load and capacities for the peak week beginning July 12, 2026, compared to the summer 2025 forecasted peak week (beginning August 3, 2025).

Description	2026 Forecast	2025 Forecast	Difference
Installed Capacity (+)	158,420	156,724	1,696
Net Interchange* (+)	783	1,184	-401
Dispatchable DSM (+)	3,049	3,056	-7
Total Capacity	**162,252**	**160,964**	**1,288**
Demand (-)	105,062	104,606	456
Interruptible Load (+)	586	1,240	-654
Maintenance/De-rate (-)	28,344	30,890	-2,546
Required Reserve (-)	8,250	8,970	-720
Unplanned Outages (-)	12,890	8,458	4,432
Net Margin	**8,292**	**9,280**	**-988**
Bottled Resources (-)	0	882	-882
Revised Net Margin	**8,292**	**8,398**	**-106**
Week Beginning	July 12, 2026	August 3, 2025	-

Table 4-1: Resource Adequacy Comparison of Summer 2025 and 2026 Forecasts (MW)

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

The Revised Net Margin for the 2026 Summer Operating Period is virtually identical when compared with the previous Summer Operating Period. The increases in installed capacity and decreases in bottled resources are offset by increases in demand and anticipated unplanned outages. The large decrease in maintenance/de-rates is associated with a proportional increase in unplanned outages due to a methodology change for Québec to more clearly communicate the flexibility Québec uses to address unplanned outages by recalling resources from maintenance. Additional information can be found in **Appendix II**.

Table 4-2 below summarizes the NPCC forecasted load and resource adequacy for the regional, coincident peak week under the 50/50, 90/10 and Above 90/10 forecast scenarios.

Reliability Coordinator-specific details, assumptions and methodologies for the forecast analyses are detailed below and in **Appendix IV**.

The Above 90/10 forecast case represents a low probability, high impact composite scenario for the Region and relies heavily on individual Area risk assumptions. The analysis serves to assess a range of system conditions and resource adequacy outcomes. Individual Area Operational Readiness mitigations are detailed in **Section 6**.

Description	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	158,420	158,420	158,420
Net Interchange (+)	783	783	783
Dispatchable DSM (+)	3,049	3,049	3,049
Total Capacity	**162,252**	**162,252**	**162,252**
Demand (-)	105,062	111,511	115,691
Interruptible load (+)	586	586	589
Maintenance/De-rate (-)	28,344	28,344	29,676
Required Reserve (-)	8,250	8,250	8,762
Unplanned Outages (-)	12,890	12,890	14,414
Net Margin	**8,292**	**1,843**	**-5,703**
Bottled Resources (-)	0	0	67
Revised Net Margin	**8,292**	**1,843**	**-5,770**
Week Beginning	12-Jul-26	12-Jul-26	19-Jul-26
Revised Net Margin %	**7.9%**	**1.7%**	**-5.0%**

Table 4-2: Resource Adequacy Comparison of 2026 Summer Forecast Scenarios (MW)

A negative Revised Net Margin, as shown in **Table 4-2** for only the Above 90/10 Forecast Scenario, indicates a combination of imports and operating procedures will be necessary to mitigate potential resource shortages. The following sections detail the Summer 2026 capacity analysis for the NPCC Region and each Reliability Coordinator.

Maritimes

The Maritimes Area declared Installed Capacity is the nameplate rating of all anticipated resources installed within the Maritimes footprint for the summer period. The net margins are calculated by adjusting the installed capacity based on expected operational conditions to include derates for variable generation, hydro flows, ambient temperatures and scheduled outages. 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 4-3** conveys the Maritimes anticipated operable capacity margins for the 50/50, 90/10 and Above 90/10 load forecasts of the Summer Operating Period during the Maritimes forecasted peak week (beginning September 20, 2026).

Description	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	8,183	8,183	8,183
Net Interchange (+)	-24	-24	-24
Dispatchable DSM (+)	0	0	0
Total Capacity	**8,159**	**8,159**	**8,159**
Peak Load Forecast (-)	3,691	3,929	4,039
Interruptible Load (+)	342	342	342
Known Maintenance & Derates (-)	2,238	2,238	2,615
Operating Reserve Requirement (-)	934	934	934
Unplanned Outages (-)	359	359	359
Net Margin	**1,279**	**1,041**	**553**
Net Margin (%)	**34.7**	**26.5**	**13.7**

Table 4-3: Maritimes Operable Capacity Forecast for Summer 2026 – Week of September 20

Above 90/10 Forecast Assumptions

The above 90/10 demand forecast assumption applies two standard deviations of the 50/50 demand forecast which is approximately 10%. The above 90/10 scenario for maintenance and derates is based on the wind capacity de-rated an additional 50% coupled with an assumed 50% reduction in natural gas fired generation. Assumptions about unplanned outages are based on historical operating experience and do not change by scenario.

New England

To determine the region's capacity risks, ISO-NE assesses factors that result in differences between New England's installed capacity and operable capacity under 50/50, 90/10 and Above 90/10 load forecasts, all of which are based on historical actual weather observations. Some of these factors include fuel deliverability risks for natural-gas-fired generation and the difference between a generator's Seasonal Claimed Capability (SCC) value and its Capacity Supply Obligation (CSO). The SCC is recognized as a generator's maximum output established through seasonal audits, whereas its CSO is its obligation to satisfy its share of New England's Installed Capacity Requirement (ICR) by generating the megawatts that cleared through a Forward Capacity Auction (FCA) within the Forward Capacity Market. **Table 4-4** breaks down New England's forecasted operable capacity margins for its lowest net margin week, week beginning July 5, 2026.

Description	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	27,962	27,962	27,962
Net Interchange (+)	409	409	409
Dispatchable DSM (+)	346	346	346
Total Capacity	**28,717**	**28,717**	**28,717**
Peak Load Forecast (-)	25,228	26,473	26,946
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	124	124	124
Operating Reserve Requirement (-)	2,062	2,062	2,062
Unplanned Outages (-)	2,275	2,275	2,275
Net Margin	**-972**	**-2,217**	**-2,690**
Net Margin (%)	**-3.9**	**-8.4**	**-10.0**

Table 4-4: New England Operable Capacity Forecast for Summer 2026 – Week of July 5

New England also compares Installed Capacity and Operable Capacity with 90/10 demand forecasts to further evaluate operable-capacity risks. This broadened approach helps operations identify potential capacity concerns for the upcoming capacity period and prepare for higher demand conditions. The analysis in **Table 4-4** above shows the further reduction in operable capacity margin recognizing these factors. The net interchange in these capacity assessments only considers the capacity cleared in capacity markets, which is much lower than actual transmission transfer capabilities. Typically, New England has imported approximately 3,000 MW during summer operating conditions. If 90/10 summer forecast conditions materialize, New England would expect to receive higher imports from neighboring Areas, as well as 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 50/50 (50th percentile), 90/10 (90th percentile) and Above 90/10 (99th percentile) demand forecasts. The 90/10 forecast has a 10% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 94.6°F.

New England forecasts the lowest Net Margin for the 2026 summer period to occur on the week, beginning July 5, 2026. The calculation for the operable-capacity margin considers summer Peak Load Exposure (PLE), which covers operating periods from May 31, 2026, through September 13, 2026. 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(s).

Above 90/10 Forecast Assumptions

ISO-NE also compares the Installed Capacity with Operable Capacity for an Above 90/10 load forecast to determine New England's capacity risks for a load associated with the warmest day in the historical dataset used to produce the analysis load data. This extended approach helps identify potential capacity concerns for the upcoming capacity period and prepare for what would be the highest demand conditions for historically observed weather conditions. This analysis shows the further reduction in the operable capacity margin recognizing these factors. Like the 90/10 forecast, if forecasted extreme summer conditions materialize and generators do not achieve their SCC, New England expects to receive higher imports from neighboring areas, as well as implement EOPs to maintain system reliability.

New York

New York determines its operating margin by comparing the baseline 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 thermal and large hydro generators. Wind generators, limited control Run-of-River hydro generators and grid-connected solar units are counted at nameplate for Installed Capacity and seasonal derates are applied. Dispatchable Demand-Side Management consists of Special Case Resources (SCRs) and Distributed Energy Resources (DERs) while Interruptible Load includes NYISO's Emergency Demand Response Program (EDRP). 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). Known maintenance and derates include 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. Beginning November 2015, NYISO started procuring operating reserves of two times the largest single generating source contingency (2,620 MW) to ensure compliance with a New York State Reliability Council (NYSRC) Rule. Unplanned Outages are based on expected availability of all thermal units and SCRs in the NYCA based on historic availability. Historic availability factors in all forced outages including those due to weather and availability of fuel. Additionally, NYISO has 3,166 MW of relief available by means of its EOPs.

Table 4-5 below presents a conservative scenario comparing the normal, 90/10 and Above 90/10 operating margins for the upcoming summer period. 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"[15] published annually in late April.

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15 NYISO Document Library – Publications - NYISO.

Description	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	37,534	37,534	37,534
Net Interchange (+)	1,918	1,918	1,918
Dispatchable DSM (+)	1,415	1,415	1,415
Total Capacity	**40,867**	**40,867**	**40,867**
Peak Load Forecast (-)	31,578	33,343	34,834
Interruptible Load (+)	1	1	1
Known Maintenance & Derates (-)	4,384	4,384	4,384
Operating Reserve Requirement (-)	2,620	2,620	2,620
Unplanned Outages (-)	2,786	2,786	3,318
Net Margin	**-500**	**-2,265**	**-4,288**
Net Margin (%)	**-1.6**	**-6.8**	**-12.3**

Table 4-5: New York Operable Capacity Forecast for Summer 2026 – Week of June 14

Above 90/10 Forecast Assumptions

The Above 90/10 summer scenario for New York was assumed to occur during a heat wave. Accordingly, a 99/1 load forecast and additional thermal generation derates based on assumed temperatures were applied.

Ontario

For the 2026 Summer Operating Period, Ontario shows negative margins under the 90/10 and Above 90/10 scenarios. If these projected negative margins do materialize and cannot be remedied by outage management, the IESO may have to rely on some imports from neighboring jurisdictions or other operating actions to ensure that Ontario's demand is met.

Table 4-6 conveys the Ontario anticipated operable capacity margins for the 50/50, 90/10 and Above 90/10 load forecasts of the Summer Operating Period during the Ontario forecasted peak week.

Description	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	38,901	38,901	38,901
Net Interchange (+)	900	900	900
Dispatchable DSM (+)	1,088	1,088	1,088
Total Capacity	**40,889**	**40,889**	**40,889**
Peak Load Forecast (-)	22,610	24,799	27,291
Known Maintenance & Derates (-)	11,394	11,772	11,794
Operating Reserve Requirement (-)	1,401	1,401	1,401
Unplanned Outages (-)	3,351	3,359	3,351
Net Margin	**2,133**	**-1,341***	**-3,848***
Net Margin (%)	**9.4**	**-5.4**	**-14.1**
*Ontario excludes firm imports from its 90/10 and Above 90/10 net margin methodologies during extreme weather to prioritize grid security and maintain strict data integrity. This approach reflects both conservative risk management and operational pragmatism, recognizing that cross-border weather events can simultaneously stress neighboring grids and jeopardize import availability. By implementing this adjustment, the IESO avoids potentially inflating net margins, eliminates the need for unrealistic outage assumptions, and directly aligns resource adequacy reporting with their Reliability Outlook to ensure a consistent, operations-driven assessment of Ontario's power grid.			

Table 4-6: Ontario Operable Capacity Forecast for Summer 2026[16] - Weeks of July 12 and 19

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 de-ratings 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 2026 period. Based on these results it is anticipated that Ontario will be energy adequate for the 50/50 weather scenario for the review period.

16 Ontario's peak week for the 50/50 and Above 90/10 scenarios is July 19, 2026. Under the 90/10 scenario, the peak week is July 12, 2026.

Month	Forecast Energy Production Capability (GWh)	Forecast Energy Demand (GWh)
May 2026	17,310	11,101
June 2026	17,494	11,829
July 2026	17,958	13,126
Aug 2026	17,581	12,786
Sep 2026	16,502	11,463

Table 4-7: Ontario Energy Production Capability Forecast by Month

Above 90/10 Forecast Assumptions

For the forecast period, the models use historical weather data from the last 31 years along with shifting that weather plus/minus seven days to have weather interact with the calendar. The result is 465 simulated values (31 years x 15 daily shifts) for each hour, 465 simulated daily peaks for each day, 465 simulated weekly peaks for each week and 465 simulated monthly peaks for each month.

For this report, the laminations from the weekly distributions are used to populate the report. For each week, the median weekly peak (50/50), the 90th percentile (90/10) and the "above 90/10" value - represented by the weekly peaks at the 99th percentile (99/01) – are included in the respective columns of the spreadsheet. The weekly peak demands are derived from the distribution of weekly peaks generated from the 465 simulations.

Resources under the respective weather scenarios are de-rated based on ambient sensitivity. The unplanned outages number is probabilistic and calculated with a variability of the weather under extreme scenarios taken into consideration.

Québec

The Québec Area anticipates adequate resources to meet demand for the 2026 summer season. The current 2026 peak forecast is 22,490 MW with a forecasted operating margin of 2,204 MW for the peak week, beginning August 2, 2026. This includes known maintenance and derates of 12,459 MW, including scheduled generator maintenance and wind generator derating. Last year, Hydro-Québec's flexibility to postpone or recall planned outages was modelled in the unplanned outages but this year it is included in the maintenance and derates. **Table 4-8** shows the factors included in the operating margin calculation.

Description	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	45,884	45,884	45,884
Net Interchange (+)	-3,670	-3,670	-3,670
Dispatchable DSM (+)	200	200	200
Total Capacity	**42,414**	**42,414**	**42,414**
Peak Load Forecast (-)	22,490	23,532	23,691
Interruptible Load (+)	250	250	250
Known Maintenance & Derates (-)	12,459	12,459	12,459
Operating Reserve Requirement (-)	1,511	1,511	1,511
Unplanned Outages (-)	4,000	4,000	5,000
Net Margin	**2,204**	**1,162**	**3**
Net Margin (%)	**9.8%**	**4.9%**	**0.0%**

Table 4-8: Québec Operable Capacity Forecasts for Summer 2026 – Week of August 2

Above 90/10 Forecast Assumptions

Two standard deviations of the load forecast uncertainty of the 50/50 forecast scenario are used to establish the above 90/10 forecast scenario. This represents a 96/4 forecast scenario. In addition to that, a generation loss of 1,000 MW is added to the unplanned outages, increasing from 4,000 to 5,000 MW.

Québec Area's power requirements are met for the greatest part by hydro generating stations located on different river systems throughout Québec. 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. Precipitation in the multi-annual reservoirs has been lower than average in the past three years. Though this decrease has led to a general reduction of exports, exports during summer peak hours are expected to remain significant.

Projected Capacity Analysis by Reliability Coordinator Area

Table 4-9 below summarizes projected capacity and margins by Reliability Coordinator area. **Appendix I** show these projections for the entire 2026 Summer Operating Period.

Area	Measure	Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	Load Forecast MW	Interruptible Load MW	Known Maint. /Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
NPCC	NPCC Peak Week	July 12, 2026	158,420	783	3,049	162,252	105,062	586	28,344	8,250	12,890	8,292
	NPCC Lowest Revised Net Margin	August 23, 2026	158,420	783	3,049	162,252	103,687	599	31,605	8,824	12,000	6,734
	NPCC Largest Revised Net Margin	September 20, 2026	158,470	783	3,049	162,302	91,773	593	35,669	8,706	11,320	15,427
	NPCC Lowest Margin	August 2, 2026	158,420	783	3,049	162,252	103,687	599	31,605	8,824	12,000	6,734
Maritimes	Peak Week	September 20, 2026	8,183	-24	0	8,159	3,691	342	2,238	934	359	1,279
	Lowest Net Margin	May 24, 2026	8,133	9	0	8,142	3,377	334	4,051	604	359	86
	NPCC Peak Week	July 12, 2026	8,133	-24	0	8,109	3,517	335	3,375	604	359	589
New England	Peak Week	July 12, 2026	27,962	409	346	28,717	25,228	0	42	2,062	2,275	-890
	Lowest Net Margin	July 5, 2026	27,962	409	346	28,717	25,228	0	124	2,062	2,275	-972
	NPCC Peak Week	July 12, 2026	27,962	409	346	28,717	25,228	0	42	2,062	2,275	-890
New York	Peak Week	July 12, 2026	37,539	3,168	1,415	42,122	31,578	1	2,866	2,620	2,897	2,162
	Lowest Net Margin	June 14, 2026	37,534	1,918	1,415	40,867	31,578	1	4,384	2,620	2,786	-500
	NPCC Peak Week	July 12, 2026	37,539	3,168	1,415	42,122	31,578	1	2,866	2,620	2,897	2,162
Ontario	Peak Week	July 19, 2026	38,901	900	1,088	40,889	22,610	0	11,394	1,401	3,351	2,133
	Lowest Net Margin	July 19, 2026	38,901	900	1,088	40,889	22,610	0	11,394	1,401	3,351	2,133
	NPCC Peak Week	July 12, 2026	38,901	900	1,088	40,889	22,519	0	11,372	1,401	3,359	2,239
Québec	Peak Week	August 2, 2026	45,884	-3,670	200	42,414	22,490	250	12,459	1,511	4,000	2,204
	Lowest Net Margin	August 23, 2026	45,884	-3,670	200	42,414	21,449	250	13,951	1,732	4,000	1,532
	NPCC Peak Week	July 12, 2026	45,884	-3,670	200	42,414	22,220	250	10,689	1,563	4,000	4,192

Table 4-9: Summary of Projected Capacity by Reliability Coordinator

Generation Resource Changes through Summer 2026

Tables 4-10 - 4-14 list the recent and anticipated generation resource additions, changes, and retirements. These effective dates represent expected fully in-service dates, though some of these facilities are expected to partially go into service prior to the effective date.

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
Maritimes	Nova Scotia Power BESS#1 - Bridgewater	+50	Storage	Q4 2025
	Nova Scotia Power BESS#2 - Spider Lake	+50	Storage	Q4 2025
	Benjamin Mills	+33.6	Wind	Q4 2025
	Nova Scotia Power BESS #3 - White Rock	+50	Storage	Q3 2026
	Higgins Mountain	+100	Wind	Q4 2026
	Eastern Kings Wind Farm	+30	Wind	Q4 2025
	Total Addition	**+313.6**		
	Total Reductions	**-1.4**		
	Net Change	**312.2**		

Table 4-10: Maritimes Resource Changes from Summer 2025 through Summer 2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
New England	Exeter Renewables	+10	Solar	Q4 2025
	Mousam River Solar	+20	Solar	Q4 2025
	Cross Town Battery	+175	Storage	Q4 2025
	Hopkinton Solar	+7	Solar	Q4 2025
	Studley Solar	+9	Solar	Q4 2025
	Western Maine Renewables	+58	Wind (Onshore)	Q1 2026
	Syncharpha Acton CSF	+4	Hybrid (Solar/Storage)	Q1 2026
	Medway Grid Battery	+250	Storage	Q1 2026
	Vineyard Wind (partial)	+650	Offshore Wind	Q2 2026
	Ocean State Power Unit 2 Uprate	+55	Dual Fuel	Q2 2026
	Vineyard Wind (remaining)	+150	Offshore Wind	Q3 2026
	Revolution Wind	+326	Offshore Wind	Q3 2026
	Oak Bluffs	-8	Oil	Q4 2025
	West Tisbury	-6	Oil	Q4 2025
	GRS-Fall River	-4	Landfill Gas	Q1 2026
	Total Additions	**+1,714**		
	Total Reductions	**-18**		
	Net Change (Nameplate)	**+1,696**		

Table 4-11: New England Resource Changes from Summer 2025 through Summer 2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
New York	Homer Solar	+90	Solar	Q2 2026
	Baron Winds II	+120	Wind	Q4 2025
	Arthur Kill Energy Storage	+15	Energy Storage	Q3 2026
	High Acres LFG	-9.6	Landfill	Q3 2026
	Total Additions	**+225**		
	Total Reductions	**-9.6**		
	ICAP Adjustment	**-378.4**		
	Net Change	**-163**		

Table 4-12: New York Resource Changes from Summer 2025 through Summer 2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
Ontario	Brighton Beach Upgrade	+43	Gas	Q1 2026
	Expedited Long Term-1 (ELT-1) Projects	+940	Storage and Gas	Q3 2026
	Same Technology Upgrades	+142	Gas	Q1 2026
	Total Additions	**+1,125**		
	Total Reductions	**0**		
	Net Change	**+1,125**		

Table 4-13: Ontario Resource Changes from Summer 2025 through Summer 2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
Québec	None	N/A	N/A	N/A
	Total Additions	**0**		
	Total Reductions	**0**		
	Modeling Adjustment	**-246**		
	Net Change	**-246**		

Table 4-14: Québec Resource Changes from Summer 2025 through Summer 2026

Maritimes

By the end of the 2026 Summer Operating Period, the Maritimes will have added approximately 280 MW since the previous summer. This is comprised of 30 MW of wind in Prince Edward Island, 100 MW of wind in Nova Scotia, and 150 MW of Battery Energy Storage Systems (BESS) in Nova Scotia. In addition, Nova Scotia anticipates a further 378 MW of wind to be installed before the end of the calendar year. A small diesel (1.4 MW) was removed from service in Prince Edward Island in 2026.

New England

During the 2026 Summer Operating Period, New England anticipates 1,696 MW of nameplate capacity for resource additions. These additions are driven by 50 MW of solar resources, 55 MW of dual fuel resources, 425 MW of storage facilities, 58 MW of onshore wind and 1,126 MW of offshore wind. While these additions are on track to obtain commercial operation status for the 2026 Summer Operating Period, many of these resources do not have a Seasonal Claimed Capability (SCC) and are not included in New England's Installed Capacity for the 2026 Summer Reliability Assessment. Despite the net gain in nameplate capacity, approximately 14 MW of oil resources and a 4 MW landfill gas resource have retired since Summer 2025.

New York

Through the 2026 Summer Operating Period, 90 MW of solar, 120 MW of wind, and 15 MW of energy storage nameplate capacity additions are expected in service. Expected total generation retirement is 9.6 MW for the upcoming season.

Ontario

Since last summer, there was a net increase in installed capacity attributed to upgrades to existing gas facilities procured via the Same Technology Upgrades Solicitation (142 MW), upgrades to the Brighton Beach gas facility (43 MW), and additional storage (621 MW) and gas (319 MW) facilities totaling 940 MW of ELT-1 projects. The total Ontario Installed Capacity is expected to be at 38,901 MW by the end of the Period.

Québec

There is little change in the total capacity of hydro generation for the Summer Operating Period of 2026 compared to summer 2025. There is a net decrease of 246 MW in available generation due to modeling updates.

Fuel Infrastructure by NPCC Area

Figures 4-1 and **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.

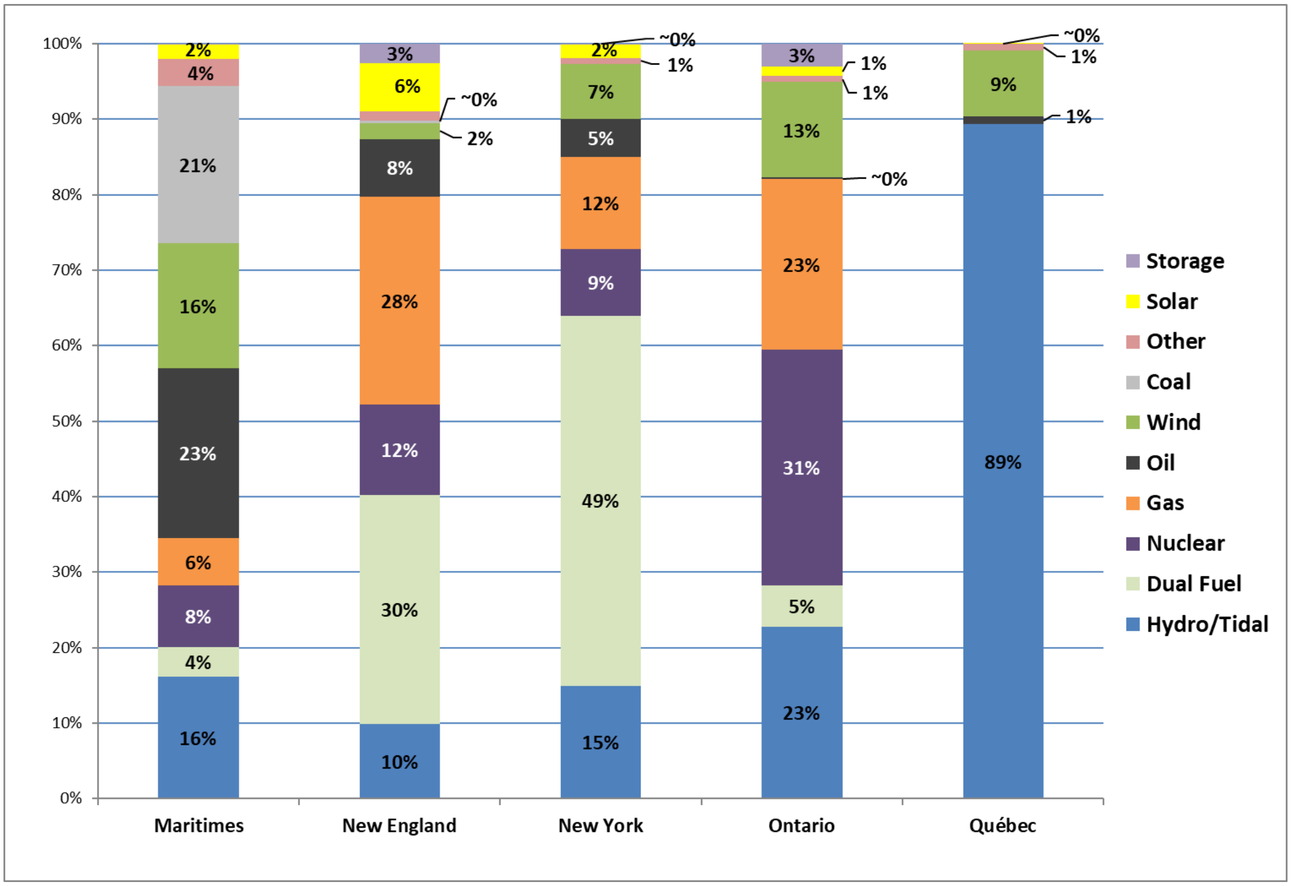

Figure 4-1: NPCC Area Reported Capacity by Fuel Type

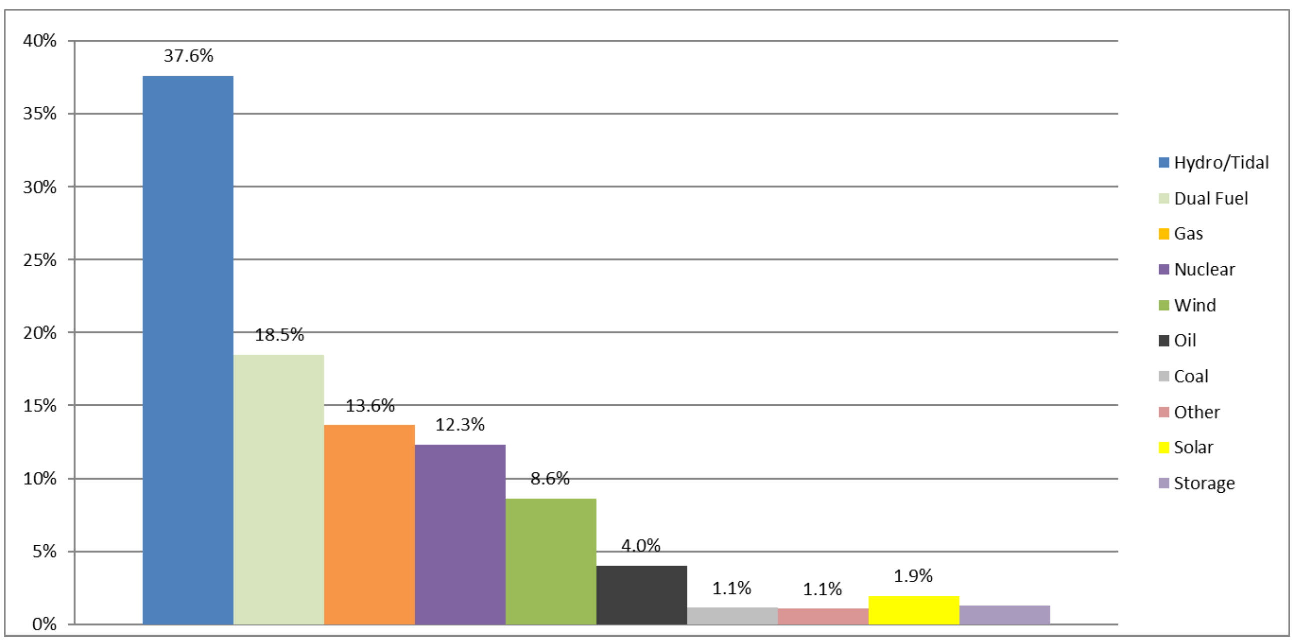

Figure 4-2: Reported Capacity Fuel Profiles for NPCC Region

Wind and Solar Capacity Analysis by NPCC Area

For the upcoming 2026 Summer Operating Period, installed wind and solar capacity accounts for approximately 10.5% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 8.6% wind and 1.9% solar. This is a small increase from 9.6% reported in 2025 (8.2% and 1.3% respectively). Reliability Coordinators have distinct methods of accounting for both 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 factors. The corresponding assumptions used in the probabilistic assessment are described in **Appendix VIII**.

Table 4-15 below illustrates the nameplate wind, solar and storage capacity in NPCC for the 2026 Summer Operating Period. The Maritimes, Ontario, New York and Québec Areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. New England (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 4-16 illustrates Behind-the-Meter (BTM) solar PV capacity and the amount of impact it has on peak load demand for each area. The IESO, ISO-NE, HQ and NYISO each factor in behind-the-meter solar as a peak load reduction. Methodologies for each area can be found in **Appendix IV**.

NPCC Area	Nameplate Wind Capacity (including Offshore)	Wind Capacity After Applied Derating Factor (including Offshore)	Nameplate Offshore Wind Capacity	Offshore Wind Capacity After Applied Derating Factor	Nameplate Solar Capacity	Solar Cap After Applied Derating Factor	Nameplate Energy Storage Capacity	Energy Storage Cap After Applied Derating Factor
Maritimes	1,341	423	0	0	148	80	162	106
New England	2,907	595	1,155	439	3,609	1,759	765	728
New York	2,994	417	136	47	661	244	23	0
Ontario	4,943	735	0	0	478	66	836	544
Québec	4,024	885	0	0	10	1	0	0
Total	**15,813**	**3,055**	**1,291**	**486**	**4,906**	**2,150**	**1,786**	**1,378**

Table 4-15: NPCC Wind, Solar and Storage Capacity and Applied Derates (MW)

NPCC Area	Installed BTM Solar PV (MW)	Impact of BTM Solar PV on Peak Load (MW)
Maritimes	162	43
New England	5,494	1,759
New York	8,486	1,657
Ontario	2,170	893
Québec	50	6
Total	**16,362**	**4,358**

Table 4-16: Behind-the-Meter Solar PV

Maritimes

Wind capacity is derated, in each reporting jurisdiction, in the following manner:

In Prince Edward Island where the wind facilities 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.

The Northern Maine Independent System Administrator (NMISA) uses a fixed capacity derate of 32 MW for the summer assessment period for their Mars Hill Windfarm.

New Brunswick and Nova Scotia apply an 18% capacity value to installed wind capacity (82% derated).

For Nova Scotia, this amount is based on the Effective Load Carrying Capability (ELCC) of wind determined through a Loss of Load Expectation (LOLE) study.[17] The LOLE study considered multiple years of historical load and wind data and simulated the system under a variety of factors.

The BTM solar is growing very slowly, and it has a small, expected impact (43 MW) on the summer peak.

New England

During the 2026 Summer Operating Period, ISO-NE has over 2,900 MW of wind resources interconnected to the grid and has derated these wind resources by nearly 80% because of established summer Claimed Capability Audits (CCAs).

Based on ISO-NE's analysis of PV performance during peak demand conditions, BTM PV[18] is expected to reduce the summer gross peak load by 1,759 MW. The percentage of nameplate

17 Attachment 17 to NS Power's Pre-IRP Deliverables Final Report at: https://irp.nspower.ca/documents/pre-irp-deliverables/.
18 See: CELT Reports

used by ISO-NE to estimate the peak demand reduction is 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 BTM PV factor continues to affect the load forecasting process, as further discussed in **Appendix IV**.

New York

For the 2026 Summer Operating Period, NYISO anticipates 9,976 MW of nameplate renewable resource capacity to be available. This includes 2,994 MW of nameplate wind and 661 MW of nameplate grid-connected solar capacity, as well as 6,321 MW of nameplate hydro. Of this, 2,719 MW of wind and 661 MW of grid connected solar capacity participate in the New York ICAP (Installed Capacity) market. Non-ICAP capacity is not included in this summation. The wind capacity was derated by 83% and the solar capacity was derated by 57% based on an estimation of the capacity factor for a representative solar unit, which is referred to as Average Capacity Factor (ACF) used in NYISO's Capacity Market.

In 2025, 7,897 gigawatt-hours (GWh) of New York's energy was produced by wind and solar resources representing approximately 6.01% of New York's electric generation. This was higher than the 2024 values of 6,515 GWh and 5.09%, respectively.

Behind-the-meter solar photovoltaic resources are expected to have a significant impact on peak loads in New York. For 2026, we estimate 8,486 MW of installed BTM PV which is forecasted to reduce peak load by 1,657 MW. This impact is reflected in New York's 31,578 MW peak load forecast. The actual impact of solar PV varies considerably by hour of day. The hour of the NYCA coincident peak varies annually. Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak will likely shift into the evening as additional BTM PV is added to the system, and as electric vehicle charging impacts increase during the evening hours.

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 five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top five 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 15%.

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 five 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 13.8%.

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.' 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 most embedded generation is solar powered, embedded generation is divided into two separate components – solar and non-solar. Non-solar, embedded generation includes generation fueled 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.

Ontario currently has visibility on 2,170 MW of embedded solar PV. 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. Consequently, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

Québec

In Québec Area, wind generation plants are owned and operated by Independent Power Producers (IPPs). HQ derates its wind by 78%. Until this year, the Québec Area derated 100% of the solar generation. For this Summer Reliability Assessment, HQ is derating and its solar generation by 88% to better reflect its operating expectations and to better align with the planning processes. Behind-the-meter solar is expected to grow to 50 MW in capacity and it is derated by 88% as well.

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 12, 2026. Definitions of the terms are included in **Appendix II**. The corresponding assumptions used in the probabilistic assessment are described in **Appendix VIII**. **Table 4-17** summarizes the Active Demand Response Programs across the NPCC region by Area.

NPCC Area	DDSM Resources (MW)	Interruptible Loads (MW)	Total (MW)
Maritimes	0	335	335
New England	346	0	346
New York	1,415	1	1,416
Ontario	1,088	0	1,088
Québec	200	250	450
Total	**3,049**	**586**	**3,635**

Table 4-17: Summary of Forecasted Demand Response Programs

Maritimes

Interruptible loads are forecast on a weekly basis and range between 327 MW and 348 MW. The values can be found in **Table AP-2** and are available for use when operational procedures are required within the Maritimes Area.

New England

ISO-NE Active Demand Capacity Resources (ADCR) can participate in the Forward Capacity Market to fulfill a market participant's capacity supply obligation pursuant to Market Rule 1, Section III.13. There is currently 346 MW of ADCR that is economically dispatchable on peak.

New York

NYISO has three demand response programs to support system reliability. NYISO currently projects 1,416 MW of total demand response available for the 2026 Summer Operating Period, consisting of approximately 927 MW of Special Case Resources (SCRs), 488 MW of Distributed Energy Resources (DERs), and 1 MW of Emergency Demand Response Program (EDRP) resources.

The EDRP provides Demand Side Resources with 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, to participate in EDRP. There are no obligations for enrolled EDRP Resources to curtail their load during an EDRP event.

The Installed Capacity (ICAP) SCR program allows demand resources that meet certification requirements to offer Unforced Capacity (UCAP) to Load Serving Entities (LSEs). The load reduction capability of 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 NYISO with two or more hours' notice, provided 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 Operating Reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, RIPs are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

The NYISO's DERs & Aggregation Participation Model allows Market Participants to group individual DERs to form a single entity—an Aggregation—that can participate in the NYISO-administered Energy, Capacity, and Ancillary Services, subject to qualification. A DER may be (i) a facility comprised of two or more different technology types located behind a single point of interconnection with a maximum Injection Limit of 20 MW, (ii) a Demand Side Resource (DSR), or (iii) a Generator with a maximum Injection Limit of 20 MW. Aggregations participate in the NYISO markets in a manner similar to traditional Generators and are required to have 6-second telemetry and must bid into the NYISO Day Ahead and Real Time markets, as applicable. An Aggregation may include a mix of DER technology types comprising a DER Aggregation or may include DER of all the same technology type comprising a Single Resource Type (SRT) Aggregation. All DER in an Aggregation must electrically map to the same Transmission Node, which is a point on the NYS Transmission System at which the applicable LBMP is calculated for an Aggregation. Aggregations participating in the Capacity market do so in a similar manner as a typical Generator and are obligated to bid into the NYISO markets, schedule themselves to produce, and notify the NYISO of any outages. Aggregations may be called upon for Supplemental Resource Availability (SRA). This process is a type of Supplemental Resource Evaluation (SRE) that is adapted for the dispatch-only operational nature of Aggregations. The SRA enables NYISO operators to reserve the available dispatch range of Aggregations.

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, demand response capacity procured through the IESO's capacity auctions, interruptible and residential DR. 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 or "ICI") and embedded generation. The load modifiers are incorporated into the demand forecast.

Québec

The Dispatchable Demand-Side Management (DDSM) operating measure is a system-wide reduction in voltage. The other DSM programs involve a reduction in industrial or commercial load. The available reduction in industrial load is somewhat reduced this year (250 MW) as a major industrial customer has reduced its available interruptible load for this summer compared with last year.

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 all 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**.

Inter-Regional 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 external 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. **Table 5-1** below summarizes the transfer capabilities between NPCC Areas and areas external to NPCC.

Area	Total Transfer Capability (MW)
Transfers from New York to	
PJM	1,515
Transfers from Ontario to	
MISO (Michigan)	1,650
MISO (Manitoba, Minnesota)	450
Transfers from Maritimes to	
Newfoundland	500
Transfers from MISO (Michigan) to	
Ontario	468
Transfers from MISO (Manitoba, Minnesota) to	
Ontario	2,930
Transfers from PJM to	
New York	1,515

Table 5-1: Inter-Regional Total Transfer Capability Summary

Ontario – Manitoba Interconnection

The Ontario – Manitoba interconnection consists of two 230 kV circuits and one 115 kV circuit. The transfers on the 230 kV interconnection points are under the control of Phase

Angle Regulator (PARs). Ontario and Manitoba are synchronously connected at 230 kV, while the 115 kV interconnection is operated normally open.

Ontario – Minnesota Interconnection

The Ontario – Minnesota interconnection consists of a single 115 kV circuit. The interconnection is under the control of a PAR. Ontario and Minnesota are synchronously connected.

Ontario – Michigan Interconnection

The Ontario – Michigan interconnection consists of two 230/345 kV circuits, one 230/115 kV circuit, and one 230 kV circuit. The interconnection is under the control of PARs. Ontario and Michigan are synchronously connected.

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 Variable Frequency Transformer (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) are expected to remain out of service for the duration of the 2026 Summer Operating Period.

Maritime Link (Nova Scotia - Newfoundland Interconnection)

The Maritime Link interconnection consists of two 200 kV High-Voltage Direct Current (HVDC) transmission lines with a total capacity of 500 MW connecting Newfoundland with Nova Scotia. The Maritime Link enables flow of hydroelectricity from Muskrat Falls generating station in Labrador to Nova Scotia.

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. **Table 5-2** below summarizes the transfer capabilities between NPCC Areas.

NPCC Area	Total Transfer Capability (MW)
Transfers from Maritimes to	
Québec	773
New England	1,000
Transfers from New England to	
Maritimes	550
New York	1,730
Québec	1,370
Transfers from New York to	
New England	2,130
Ontario	1,600
Québec	1,100
Transfer from Ontario to	
New York	1,900
Québec	2,145
Transfers from Québec to	
Maritimes	1,200
New England	3,537
New York	3,329
Ontario	2,930

Table 5-2: Inter-Area Total Transfer Capability Summary

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 2026 Operating Period under expected and peak demand configurations and have provided the following review as well as identified transmission improvements listed in **Table 5-3**.

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	None	N/A	N/A
New England	New England Clean Energy Connect (NECEC) (HQ-NE HVDC Tie Line)	320 HVDC	Q1 2026
	3027 Line Maine Area Transmission Upgrade)	345	Q4 2025
	Buxton Statcoms (Maine Area Transmission Upgrade)	345	Q4 2025
New York	Champlain Hudson Power Express (CHPE)	400 HVDC	Q2/Q3 2026
	Smart Path Connect (SPC)	345, 230	Q2 2026
Ontario	Lakehead TS - Mackenzie TS: Reinforcement	230	Q4 2026
Québec	Anjou substation	315	Q3 2025
	NECEC	320 HVDC	Q1 2026
	CHPE	400 HVDC	Q2/Q3 2026

Table 5-3: NPCC – Recent and Future Transmission Additions

Maritimes

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the 2026 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**).

New England

New England Clean Energy Connect (NECEC) is a symmetric monopole +/- 320 kV HVDC line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road located in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England. The 3027 line (Coopers Mills – Maine Yankee) is a 345 kV line required by the NECEC system impact study to prevent the project from causing adverse impact to the pre-existing system with Surowiec-South interface transfers increased to 2,200 MW. Additionally, there are two new +/- 300 MVA STATCOMS being placed at Buxton Station in southern Maine which will improve voltage stability in the area and increase the Surowiec-South stability limit by 1,000 MW, from pre-NECEC planning limits, which equals 2,800 MW. These transmission improvements have reinforced the overall reliability of the system and reduced transmission congestion, enabling economic power to flow more easily around the entire region. The improvements support decreased energy costs and increased power system flexibility.

New York

For the 2026 Summer Operating Period, New York does not anticipate any reliability issues for operating the bulk power system.

In Q2 or Q3 of 2026, the Champlain Hudson Power Express HVDC tie-line from Québec to New York City is expected to be in service. The Smart Path Connect transmission upgrade is in progress continuing in Q2 2026. Additionally, the Hudson-Farragut and Marion-Farragut PAR controlled 230/345 kV (B3402 & C3403) circuits are expected to be out of service for the 2026 Summer Operating Period.

Ontario

For the Summer 2026 Operating Period, Ontario's transmission system is expected to be adequate. Generally, Ontario is operating within a period of challenging conditions due to a significant number of major generation and transmission projects either currently underway or expected to begin soon. Phase 1 of the Waasigan Transmission Project, which includes construction of a new double-circuit 230 kV line between Lakehead Transformer Station (TS) and Mackenzie TS, is targeted for completion by Q4 2026. This project will strengthen system reliability and support growing demand in Northwest Ontario. The IESO has been actively coordinating and planning outages with market participants to maintain reliability.

Outages affecting neighboring jurisdictions can be found in **Table 5-7**: Ontario Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the Summer 2026 season but may coordinate with neighbors to reschedule outages should a low reserve scenario come to materialize especially in July 2026.

Québec

In the Québec Reliability Coordinator Area, 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. Furthermore, some of these outages can be postponed or recalled when heat waves are forecast. Therefore, these outages should not impact inter-area transfers to neighboring systems. During the 2026 Summer Operating Period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring Reliability Coordinator Areas to leave maximum capability to summer peaking areas.

In comparison to the last summer assessment, the Québec system in summer 2026 will have a new 320 kV HVDC interconnection NECEC for 1,200 MW between Appalaches substation in Québec and Merill Road substation in ISO-NE, and a new 400 kV HVDC interconnection CHPE for 1,250 MW between Hertel substation and Astoria in NYISO, as well as a new 315 kV substation in the Montreal region (Anjou).

Area Transmission Outage Assessment

This section and **Tables 5-4** through **5-8** below outline any known scheduled outages on interfaces between Reliability Coordinators. The table for each Area lists the outages that the respective Area is responsible for publishing, as well as for notifying any affected Areas. Some redundancy exists for interconnection outages, as both connected Areas share joint responsibility for reporting these events.

Maritimes

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Québec	Circuit 1 (Eel River)	2026/04/06	2026/04/19	175 MW Bilateral
Québec	Circuit 2 (Eel River)	2026/04/16	2026/04/28	175 MW Bilateral
Québec	Circuit 1 (Eel River)	2026/09/13	2026/09/19	175 MW Bilateral
Québec	Circuit 2 (Eel River)	2026/09/27	2026/10/23	175 MW Bilateral
ISO-NE	NB-NE	2026/04/10	27/07/27	550 MW Import 650 MW Export

Table 5-4: Maritimes Area Transmission Outage Assessment

New England

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Québec	NE-HQHI	2026/06/02	2026/06/02	170 MW Export
Maritimes	NE-NB	2026/06/08	2026/06/10	730 MW Import 550 MW Export
Québec	NE-NQHI	2026/06/15	2026/06/16	170 MW Export
Québec	NE-HQHI	2026/06/22	2026/06/26	170 Export
Québec	NE-HQHI	2026/07/06	2026/07/10	170 Export
Maritimes	NE-NB	2026/07/20	2026/07/30	650 MW Import 550 MW Export

Table 5-5: New England Area Transmission Outage Assessment

New York

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
ISO-NE	Northport	02/26/2026	05/15/2026	100 MW Import
Ontario	PA301	04/27/2026	05/01/2026	1,350 MW Import
Québec	Chateauguay	05/03/2026	05/06/2026	1,500 MW Import
ISO-NE	CSC	05/03/2026	05/15/2026	330 MW Import
Ontario	PA27	05/04/2026	05/08/2026	100 MW Import
Ontario	BP27	05/10/2026	05/15/2026	400 MW Import
Ontario	AT4	05/11/2026	05/30/2026	100 MW Import
Ontario	PA27	09/15/2026	11/17/2026	100 MW Import

Table 5-6: New York Area Transmission Outage Assessment

Ontario

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Québec	A42T	2026/06/10	2026/06/16	530 MW PQAT Export 625 MW PQAT Import
New York	BP76	2026/05/11	2026/05/15	500 MW Export 150 MW Import

Table 5-7: Ontario Area Transmission Outage Assessment

Québec

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Maritimes	NB	2026-08-17	2026-08-27	300 Export
Maritimes	NB	2026-09-14	2026-09-24	230 Export
New York	DEN	2026-09-14	2026-10-08	75 Export 100 Import
New York	MASS	2026-05-03	2026-05-06	1,800 Export 1,000 Import
New York	MASS	2026-06-29	2026-07-02	1,000 Export 1,000 Import
New England	Derby	2026/05/11	2026/05/28	62 MW Export
New England	Highgate	2024/07/27	2026/08/13	225 MW Export 170 MW Import
New England	NE	2026/05/31	2026/06/13	2,000 MW Import
Ontario	LAW	2026/07/27	2026/08/13	65 MW Export 105 MW Import

Table 5-8: Québec Area Transmission Outage Assessment

6. Operational Readiness for Summer 2026

NPCC

NPCC promotes and provides a forum for the active coordination of reliability and operation of the international, interconnected bulk power system within northeastern North America. NPCC Task Forces and Working Groups support continued reliability operations prior to and throughout the Summer Operating Period by reviewing and assessing the performance of the Bulk Power System (BPS).

In addition to conducting pre-seasonal reliability assessments, NPCC also coordinates periodic and specific operational communications to ensure that potential system changes and outages for operations are properly reviewed. Whenever adverse system operating or weather conditions are expected or encountered, any RC Area or NPCC Situational Awareness Staff, may request an Emergency Preparedness Conference Call[19] to discuss issues related to the adequacy and security of the interconnected bulk power supply system with appropriate operations management personnel from the NPCC RC Areas, NPCC staff and neighboring systems. These procedures are frequently tested on a continual basis throughout the year. NPCC also conducts Weekly Conference Calls to review a seven-day outlook for the Region, including largest contingencies, operating margins, and weather, as well as to ensure that future system changes, such as generation and transmission outages that have the potential to affect neighboring Areas are coordinated.

The region also actively monitors all types of weather, including solar storms, as power system reliability can be affected under certain conditions. Both NERC and NPCC have implemented standards[20] and procedures[21] requiring entities to mitigate the potential effects of geomagnetic disturbances.

Lastly, NPCC supports Electric-Gas Operations reliability coordination efforts to promote interdependent sector communications, awareness, and information sharing.

In addition to coordinated regional activities, NPCC Reliability Coordinator-specific readiness activities and real-time procedures are detailed in **Table 6-1** below. The table provided illustrates a potential set of real-time solutions in the event of a low likelihood, high impact "Above 90/10" scenario as described in **Section 4**. In addition to the actions in this table, it is likely that Areas will look to obtain non-firm imports or re-schedule maintenance if this scenario were to occur.

19 See: NPCC C-01, NPCC Emergency Preparedness Communications Procedures.
20 See: NERC EOP-010-1, Geomagnetic Disturbance Operations.
21 See: NPCC C-15, Procedures for Geomagnetic Disturbances Which Affect Electric Power Systems.

Actions	Maritimes	New England	New York	Ontario	Québec[22]
Allow depletion of Operating Reserve	934	~600	2,620 (30 Min) 1,310 (10 Min)	473/945	~750
Curtailment of interruptible load	already included	-	1	-	already included
Manual Voltage Reduction	N/A	Variable (0 - 375)	526	1.3%-1.8%	already included
Curtailment of non-essential Market Participant load	N/A	-	-	-	-
Voluntary curtailment of large LSE customers	N/A	200	255	-	-
Public Appeals	80	300	74	1%	-
Additional Actions	N/A	Variable (45 – 2,545)[23]	1,000[24]	-	-
Total Assumption Range	1,014	1,145 – 4,020	3,166 – 4,476	2,046–2,182	750
Lowest Above 90/10 Net Margin Week	**May 24, 2026**	**July 5, 2026**	**June 14, 2026**	**July 19, 2026**	**Aug 30, 2026**
Lowest Above 90/10 Net Margin MW	**-705 (-19.1%)**	**-2,690 (-10.0%)**	**-4,288 (-12.3%)**	**-3,848 (-14.1%)**	**-952 (-4.2%)**
Lowest Above 90/10 Net Margin With Real-Time Procedures Relief	**309 (8.3%)**	**-1,545 (-5.7%)**	**188 (0.5%)**	**-1,666 (-6.1%)**	**-202 (-0.8%)**

Table 6-1: Real-Time Procedures and Expected Relief (MW)

22 Interruptible Load (870 MW), and Voltage reduction (150 MW) are directly integrated (Above 90/10 assumptions in **Section 4**) and are therefore not considered as a 'Real time' procedure.
23 See ISO-NE OP4 - Appendix A - Estimates of Additional Generation and Load Reliefs (iso-ne.com).
24 See Emergency Operations Manual: Manuals, Tech Bulletins & Guides - NYISO. Up to 1000 MW of emergency purchases may be available.

Maritimes

Voltage Control

The Maritimes Area, in addition to the reactive capability of the generating units, employs a few capacitors, reactors, synchronous condensers and a Static VAR Compensator (SVC) to provide local area voltage control.

Operational Procedures

The Maritimes is a winter peaking area and as a result, 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. Steps that can be taken to balance supply with demand include reducing dispatchable generation down to minimum operating levels, taking generation units offline that can be restarted in time for the next peak load, and attempting short-term energy sales. If those steps are not adequate to alleviate the over-supply, then individual wind farm generation can be curtailed in blocks until the supply demand imbalance is alleviated.

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.

New England

Voltage 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 evaluation software. ISO-NE also reviews and coordinates Load Power Factor requirements in the region, which accounts for the potential impact of the distribution load on the BPS 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 voltage limits for the BPS 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. For the 2026 Summer Operating Period, ISO-NE does not anticipate issues managing light load conditions. In the event the region's reactive devices are not sufficient, ISO-NE will commit the necessary area generation to help control voltage.

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 of 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 that 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,[25] 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 summer peak of 26,997 MW and a net 50/50 summer peak of 25,228 MW. The net demand forecast considers a demand reduction of 1,759 MW of BTM PV and 10 MW of BESS. Historical hourly loads are reconstituted for the impacts of EE and BTM PV to ensure the proper accounting of EE and BTM PV, which are both forecast separately. The 2026 BTM PV forecast reflects recent development trends in the region, as indicated by data provided by regions' Distribution Owners, and updated policy information provided by the New England states.[18]

In the day-ahead load-forecast process, BTM PV is explicitly forecasted and included in several demand models. Multiple methods are used to best estimate the impact of BTM PV on net demand. Production data is received daily and used for refinement of the BTM PV forecast models. Efforts to improve BTM PV forecasts in the short-term and real-time process are ongoing and are expected to continue for the foreseeable future.

Behind-the-Meter Photovoltaic (BTM PV)

Since 2014, BTM PV has had great impact on ISO New England's daily demand curves. BTM PV is tied to the distribution system, and therefore, the control room has no visibility of the resources. A large increase of BTM PV installed in New England is contributing to significant volatility in system load during the day. It is becoming common to see mid-afternoon loads dip below overnight lows when the sun is shining bright.

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 considering 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

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25 Operating Procedure No. 13 is located on the ISO's website at: ISO-NE OP13 - Standards for Voltage Reduction and Load Shedding Capability.

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 2026 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.[26]

Operating Procedures

For the 2026 Summer Operating Period, 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.[27]

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.[28]

3. ISO-NE's Operating Procedure No. 21 - Operational Surveys, Energy Forecasting & Reporting 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.[29] Fuel supply deficiencies are the temporary or prolonged disruption to regional fuel supply chains for coal, natural gas, Liquid Natural Gas (LNG), and heavy and light fuel oil.

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26 System-and-market-ops-report-May-2026.pdf
27 Operating Procedure No. 4 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf.
28 Operating Procedure No. 7 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf.
29 Operating Procedure No. 21 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

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 24.5% for 2026. NYSRC Executive committee adopted the Special Sensitivity as the Final Base, produced an IRM of 25.6% and "Minimum Locational Capacity Requirements" (MLCRs) of 79.8% and 107.5% for Load Zone J and Load Zone K, respectively for the period May 2026-April 2027.[30]

The actual 2025 peak was 31,857 MW, 1,478 (1.2%) higher than the forecast of 31,471 MW. The current 2026 peak forecast is 31,578 MW. It is higher than the 2025 forecast by 107 MW (+0.3%). The forecast based on 90/10 weather conditions, set to the 90th percentile of typical peak-producing weather conditions for 2026 is 33,343 MW. The baseline summer peak demand forecast accounts for load increases due to New York State electrification and decarbonization policies, principally the 2019 Climate Leadership and Community Protection Act ("CLCPA"), as well as the Advanced Clean Cars II and Clean Trucks regulations. The baseline forecast includes electrification via conversion to electric vehicles and electrification of non-weather sensitive end-uses. Significant load-reducing impacts occur due to energy efficiency initiatives and the growth of distributed BTM energy resources, such as solar PV. These impacts result primarily from New York State's energy policies and programs, including the Clean Energy Standard ("CES"), the NY-SUN initiative, the energy storage initiative, and other NYPSC and NYSERDA programs.

In 2026 it is estimated that the peak load forecast will be reduced by 729 MW for energy efficiency impacts, 1,657 MW for behind-the-meter PV impacts, 354 MW for other distributed generation impacts, and 281 MW for behind-the-meter energy storage. Projected electric vehicle usage will increase the peak load forecast by 270 MW.

NYISO maintains Joint Operating Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement or supply of emergency energy, and provisions for wheeling emergency energy from remote areas, if required. Prior to the operating month, the NYISO identifies to neighboring control areas the capacity-backed transactions that are expected to be both imported into and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2026 Summer Operating Period, New York expects to have 3,583 MW of firm import capacity available, and 415 MW of firm sales based on current external purchases and sales.

NYISO anticipates sufficient resources when considering the supply and demand statewide. However, the New York City locality has reliability needs in summer 2026 which are being addressed through the Short-Term Reliability Process. Local system issues are also observed in Far Rockaway load pocket in Long Island which are also being addressed through the Short-Term Reliability Process. Statewide peak demand can be met without the need to

[30] See: 2026-2027 IRM Study: Database Alignment Report.

resort to emergency operations. Additionally, 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 demand response 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

High voltage conditions are occurring more frequently, mainly during shoulder seasons, driven by low load, lightly loaded transmission lines, limited dynamic voltage support devices, and evolving system conditions. Evolving system changes are increasing the frequency and operational complexity of high voltage conditions, and operational tools and corrective actions traditionally used as last-resort measures are being required more routinely, indicating tighter voltage control margins. Dynamic reactive support devices play a critical role but are increasingly operated outside normal ranges. Voltage control actions carry operational and cost impacts, including increased reliance on supplemental resource requests, Voltage Support Services (VSS) calls, and transmission actions concentrated on specific regions.

Generators are compensated for reactive capability outside the standard power factor range and are required to always maintain their automatic voltage controlling equipment (AVRs, inverters, etc.) in service for said compensation. Generators must adjust their VAR output when called upon to provide voltage support. The New York Control Area (NYCA) also has two SVCs at Fraser and Leeds as well as a Convertible Static Compensator (STATCOM) at Marcy that 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

The New York State Department of Environmental Conservation (NYSDEC) finalized regulations in 2019 to implement stricter ozone season NO_X emissions rate limits to reduce ozone-forming pollutants associated with New York State-based simple cycle combustion turbine generation. These compliance obligations, referred to as the "Peaker rule," impacted a total of 3,300 megawatts. Emission rate reduction requirements are established in two phases, effective May 1, 2023, and May 1, 2025. NYISO has accounted for the unavailability of generators affected by the DEC Peaker Rule based on compliance plans submitted to the DEC by the affected generators, which are principally located in Zones J and K. Of the 3,300 MW, approximately 1,000 MW retired or limited their operations before May 1, 2023. Another 600 MW of peakers would have become unavailable beginning May 1, 2025, except for those that were designated under the "peaker rule" as necessary to be temporarily retained to maintain electric system reliability until permanent solutions are deployed. The DEC regulations include provisions to allow an affected generator to continue to operate for up to two years, with a possible further two-year extension, after the compliance deadline if the generator is designated by the NYISO or by the local transmission owner as needed to resolve a reliability need.

The NYISO previously determined that temporarily retaining the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges was necessary to address ongoing reliability needs, and the NYISO's designation of these generators in accordance with the Peaker Rule allows their continued operation until May 1, 2027 or until permanent solutions are in place. In the most recent Short-Term Reliability Process Report issued on April 15, 2026[31], reliability needs due to supply deficiencies continue to require Gowanus 2 & 3 and Narrows 1 & 2 barges to be available and to operate. Without the retention of these generators, the New York City and Lower Hudson Valley areas would be deficient during expected summer weather peak demand periods. The NYISO has submitted a letter to the DEC designating the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit extension date allowed under the Peaker Rule.

Remaining peaker units have stated either that they comply with the emission limits as currently operated, or proposed water injection equipment upgrades to achieve the more stringent emissions limits. The availability of these generators, which function as quick start reserves, may reduce the need to run more generators at lower dispatch levels while ensuring reliable operations. These generators may also be called upon to fully respond to NYISO dispatch signals, which could occur during long duration hot weather events or following the loss of significant generation or transmission assets in NYC.

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.

Ontario

Supply/Demand Balance

Ontario is currently showing negative margins for a number of weeks under the 90/10 scenario. This means some reliance on imports from neighbors can be expected during these

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31 The April 15, 2026 Short-Term Reliability Process Report: 2026-2030 Generator Deactivation Reliability Needs (2025 Quarter 3 STAR) solution selection report summarizes the NYISO's evaluation and selection of solutions to address the needs in New York City, Long Island, and the Lower Hudson Valley (Link).

weather conditions if these projected negative margins do materialize and cannot be remedied by outage management.

With the foreseeable future projected to be under tighter supply conditions, surplus baseload generation will be much less of a concern than it has been in recent years.

Under light load conditions, the removal of one or more 500 kV circuits for voltage control in eastern Ontario will remain as a viable option to reduce voltage.

Embedded solar and wind generation will continue to reduce demand on the transmission system, during summer peaks. The summer peaks will also be subject to lower demands due to the Industrial Conservation Initiative[32] (ICI).

Outage Management

Outage coordination will be important in the next years given the significant amount of capital upgrades, such as refurbishment outages and station rebuild, which are happening at the same time as routine maintenance. It will be one of the first tools to be utilized to minimize risks to meeting demand. Market Participants have been strongly encouraged to review ahead and coordinate plans with the IESO to ensure their outages can be appropriately scheduled.

Seasonal Readiness

Ontario will continue to use existing programs such as unit readiness to prepare for this summer. Testing generation may identify concerns to be remedied and may provide updated information in development of the operating plan.

Québec

Equipment Maintenance

Most transmission lines, transformers and generating unit maintenance are done during the summer period. The maintenance outages are planned so that firm exports can be maintained. The most significant operating measure to increase available capacity is the proactive management of outages. For example, some outages may be recalled and others not granted if operating conditions were to degrade.

Real-time Procedures

Real-time operating procedures such as Interruptible Load and Manual Voltage Reduction have been directly included in the margin assessments since 2025. The only real-time

32 For more information on the ICI, see: Industrial Conservation Initiative Backgrounder and FAQs.

procedure retained for the real-time procedures table is the depletion of some of the Québec Area operating reserves.

Voltage Control

Québec is a winter peaking area, so the reactive capability of generators is not a problem during summer periods. Hydro-Québec does not expect to encounter any kind of low voltage problem during the summer. On the contrary, the principal concern during the summer is controlling over-voltages on the 735 kV network. This is accomplished mainly with the use of shunt reactors and the proactive switching of transmission lines out of service. Typically, about 15,000 MVAR of 735 kV shunt reactors are connected at any given time during the summer, with seven to ten 735 kV lines being out of service for maintenance or voltage control. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

Thermal Limits

On a few occasions during the last summers when temperatures were high in southern Québec, some 735 kV lines became heavily loaded because of their lower thermal limit and the increased cooling load in southern Québec. Since those occasions, Hydro-Québec systematically reviews and optimizes its thermal limits to ensure that no equipment becomes overloaded following a contingency in hot weather.

Forest Fires

During the summer of 2023, Québec faced its most severe forest fire season in modern history, surpassing the previous record set in 1923. Over 1M hectares were burned, which is a nearly 10-fold increase over the prior 10-year average. The wildfires began on May 28, 2023, with transmission lines starting to trip on May 31st on the Churchill Falls – Arnaud transmission corridor and from June 1, 2023, on James Bay transmission corridors. Throughout June and July of 2023, several 735 kV lines tripped.

The 2024 and 2025 forest fire seasons were significantly below the 10-year average in area burned, despite continued overall dryness in the northern parts of Québec.

Hydro-Québec operating procedures for forest fire conditions include recalling planned outages, requiring additional operating margins to mitigate the impact of line tripping, preparing contingency plans, and other daily optimization of system configurations and operations.

If severe forest fire conditions recur in 2026, Hydro-Québec expects to be able to maintain its system reliability. However, the capacity of the Hydro-Québec system to support its neighbors during such conditions could be reduced.

Summer 2026 Solar Terrestrial Dispatch[33] Forecast of Geomagnetically Induced Current (GIC)

Solar Cycle 25 appears to have peaked in October 2024 with a smoothed sunspot number of 160.9. However, there remains a small possibility of a double peak in the current cycle, as has occurred in many previous sunspot cycles (see the blue line in **Figure 6-1** below).

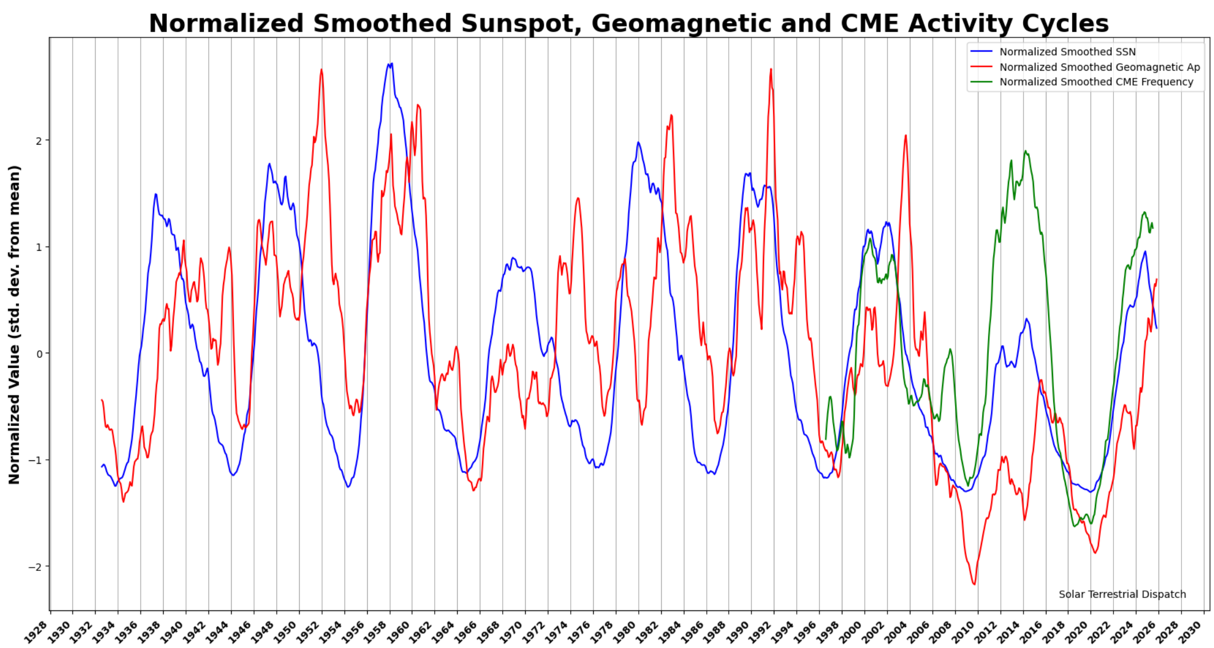

Figure 6-1: Normalized Smoothed Sunspot, Geomagnetic, and CME Activity Cycles

In this figure, the blue line shows smoothed sunspot numbers since 1932 (covering the last eight solar cycles). The red line shows smoothed geomagnetic activity over the same period, and the green line shows the smoothed monthly frequency of coronal mass ejections, as compiled by the SOHO/LASCO team[34]. The data are normalized, with the zero line on the Y-axis indicating the mean, so values above or below zero are standard deviations away from that mean. This allows for a direct comparison among the sunspot, geomagnetic activity, and CME cycles, and highlights the delay between peaks in sunspot numbers (blue) and peaks in geomagnetic activity (red).

The red line indicates that we are still moving toward the peak of the geomagnetic activity cycle, which is expected over the next year or two. Although the numbers of sunspots and coronal mass ejections (blue and green) should begin to decline during this period, the threat of strong Earth-directed CMEs will likely remain high. This is because the more complex

33 See: Solar Terrestrial Dispatch (spacew.com).
34 The CME catalog used in this plot is generated and maintained at the CDAW Data Center by NASA and The Catholic University of America in cooperation with the Naval Research Laboratory. SOHO is a project of international cooperation between ESA and NASA.

sunspot groups tend to form closer to the solar equator as we progress through the solar cycle, placing them more directly in line with Earth.

Major geomagnetic storms, and occasional severe storming, are expected to continue over the next year or two. Geomagnetic K indices greater than six will remain possible and may induce moderate to strong electrical currents in power grids.

One feature of this phase of the solar cycle is the prominence of coronal holes, which are regions of the Sun where open magnetic field lines allow solar plasma to escape more easily and at high speed into space. These high-speed streams are generally more stable and longer-lived during the declining phase of the solar cycle. This makes longer-range forecasts of geomagnetic activity more reliable.

At present, based solely on the current morphology of existing coronal holes, periods of enhanced geomagnetic activity that could include minor to moderately strong GIC activity are expected on or near the following dates this spring and summer:

- May 9
- May 16-17
- May 27-28
- June 5
- June 12-13
- June 23-24
- July 2
- July 9-10
- July 20-21
- July 30
- August 6
- August 17-18
- August 26
- September 2-3
- September 13-14
- September 29-30

Please note that coronal holes do change shape over time. Although they generally become more stable as the solar cycle declines, they can still be altered by factors such as the formation of new sunspot regions. These dates should therefore be used as guidance only, not as a definitive prediction.

Operators are encouraged to monitor daily geomagnetic activity forecasts this spring and summer through the Geomagnetic Storm Mitigation System (GSMS) interface. Forecasts are updated at least once daily and may be updated several times a day during disturbed periods.

7. Post-Seasonal and Historical Review

Summer 2025 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator Area's Summer 2025 operational experiences. The NPCC coincident peak was 107,004 MW and occurred on June 24, 2025, at HE 19 EDT. New England, New York, and Ontario all experienced their 2025 summer peaks on the same day as the NPCC coincident peak. June 24 is a major holiday in Québec, which played a crucial role in stabilizing the NPCC region during a wide-spread heat wave that day.

Additional details from Summer 2025 can be found in **Appendix VIII - CP-8 2025 Summer Multi-Area Probabilistic Reliability Assessment**, Section 5, "Historical Review".

Maritimes

The Maritimes demand during the 2025 NPCC coincident peak was 3,260 MW. Maritimes actual peak was 3,528 MW on August 11, 2025 at HE 17 EDT. Two events were reported during the Summer 2025 period. Nova Scotia declared an Energy Emergency Alert (EEA)[35] 2 on April 4 and EEA 1 on July 13. This information was shared with Québec and ISO-New England.

New England

The New England peak demand coincided with the 2025 NPCC coincident peak and was 26,024 MW.[36] Peak loads were generally in line with forecasts given the weather conditions on the peak day. On June 24, 2025, ISO New England declared an emergency and implemented Operating Procedure No. 4 (OP-4) after unexpected generator outages totaling 2,560 MW coincided with high temperatures, forcing the system to operate with minimal capacity margins. The event, which included Capacity Scarcity Conditions and EEA 1 alerts, caused peak system load to hit 26,024 MW. Neighboring Areas were also experiencing tight system conditions; IESO, NYISO, and PJM all declared EEA 1 on June 24. ISO-NE declared M/LCC 2, Abnormal Conditions Alert, for capacity deficiency on June 23 - June 25 and July 16 – July 17.

New York

Summer 2025 featured severe heatwaves, with June 24 matching the 2013 record for Cumulative Temperature and Humidity Index (86.8°F) and driving real-time loads toward 90/10 forecast levels. Tight capacity conditions required NYISO to declare EEA 1, activate

35 For information on EEA Levels, See NERC Procedure EOP-011-4.
36 New England Actual Peak does not account for load served by Settlement Only Generators.

EDRP/SCR resources, and issue energy warnings/watches, while behind-the-meter solar shifted net load peaks later in the afternoon.

The New York demand during the 2025 NPCC coincident peak was 31,720 MW. The New York peak demand value of 31,857 MW occurred on June 24, 2025, HE 18 EDT reaching 101.2% of the baseline forecast. To manage the load, NYISO activated EDRP and SCR resources across all zones and called on External ICAP suppliers (HB14–21 daily). Retail demand response programs were also utilized to mitigate peak demand. Energy Watch and Energy Warning alerts were raised when supply reserves decreased below 1,965 MW. Demand response programs were in effect for the three days of high demand: June 23, 24, and 25. On 24 June, NYISO operators initiated emergency energy purchases to meet approximately 2,000 MW of demand. On-peak wind supply peaked at 1,600 MW.

During the summer of 2025, New York experienced a critical ten-day period of 83°F temperatures and high outage rates that severely limited available energy resources. This period marked a shift in operations, as NYISO utilized external capacity multiple times during that summer despite such requests being rare in the past.

Ontario

The Ontario demand coincided with the 2025 NPCC coincident peak and was 24,862 MW. This was higher than the original 2025 90/10 forecast of 24,231 MW. An EEA 1 was declared during this event. Several other high demand periods also occurred from June throughout August. Multiple resources were utilized to meet this demand, including demand response and imports. In Ontario, the IESO issued an EEA 1 on September 23, 2025, citing potential operating reserve shortfalls caused by less imports than scheduled in day-ahead, higher than forecasted loads and significant generation maintenance outages. Hydro-Québec faced particularly tight operating conditions due to warmer temperatures and low water levels, which stressed its hydroelectric generation resources and led to unanticipated maintenance extensions and generation unavailability, hence, unable to support IESO. NYISO revised limits to allow imports over peak.

Québec

The Québec Area actual internal peak demand for summer 2025 and all-time summer peak demand occurred on August 11, 2025, at HE18 EDT and was 22,962 MW. This is the third consecutive summer recording a new all-time summer peak demand, though it did not exceed the 50/50 forecast. Higher than usual temperature is again the main contributor to the last year's historical peak occurrence. Although Québec had its historical summer peak last year, it is important to emphasize the fact that Hydro-Québec's system is designed for a winter peaking load of 75% above this peak summer load.

Whereas in recent years, Québec's system summer peak has coincided with the NPCC peak, 2025 Québec's system peak did not. The NPCC peak was on June 24, which is a statutory holiday in Québec, and consequently, the load on June 24th is usually significantly reduced even on hot days. On June 24th, 2025, the Québec system provided significant exports to all neighboring systems.

In general, the Québec system exported significantly during NPCC's summer peaks in 2025. However, due to lower water levels in northern reservoirs, exports from Québec during the entire summer period were significantly lower than in previous years. Indeed, the Québec system was a net importer during many summer hours.

Historical Summer Demand Review

Table 7-1 below summarizes the actual historical non-coincident summer peak demands for each NPCC Balancing Authority area over the last ten years along with the forecasted 50/50 coincident peak demand for Summer 2026.

Summer	NPCC Coincident Demand Date	NPCC Coincident Demand	Maritimes	New England	New York	Ontario	Québec
2016	Aug. 11, 2016	103,350	3,391	25,466	32,076	23,213	20,724
2017	June 12, 2017	96,911	3,118	23,708	29,699	21,786	21,118
2018	Aug. 28, 2018	103,231	3,243	25,808	31,861	23,240	21,448
2019	July 4, 2019	98,578	3,236	24,004	30,397	21,791	20,493
2020	July 27, 2020	102,722	3,346	24,736	30,660	24,446	21,850
2021	Aug. 26, 2021	103,461	3,443	25,801	30,919	22,986	22,480
2022	Aug. 08, 2022	100,427	3,435	24,330	30,505	22,607	22,480
2023	Sept. 06, 2023	100,408	3,389	23,521	30,206	23,713	22,780
2024	June 19, 2024	99,724	3,518	24,310	28,990	23,852	22,961
2025	June 24, 2025	107,004	3,528	26,024	31,857	24,862	22,962
2026 Forecasted	July 12, 2026	105,062	3,691	25,228	31,578	22,610	22,490

Table 7-1: Ten Year Historical Summer Peak Demands (MW)[37]

Table 7-2 below presents the all-time summer peak demand for each NPCC Area with the corresponding date and time.

NPCC Area	Load (MW)	Date and time
Maritimes	3,886	May 16, 2007, HE 08 EST
New England	28,130	August 2, 2006, HE 19 EST
New York	33,956	July 19, 2013, HE 19 EST
Ontario	27,005	August 1, 2006, HE 16 EST
Québec	22,962	August 11, 2025, HE 18 EST

Table 7-2: All-Time Summer Peak Demand by Area

37 The cells highlighted in light blue represent the highest non-coincident summer peak demand in the last ten years for each Area.

The degree of coincidence between the summer peaks of the NPCC Areas varies from year to year based largely on the movement of weather patterns in the Region. **Figure 7-1** below demonstrates the relationship between relative daily stress of an individual Area (measured in the Area's daily summer peak loads divided by the Area's overall summer peak load) versus the relative daily stress of the NPCC region (measured in the Region's daily summer coincident peak loads divided by the Region's overall summer coincident peak load) by measuring the Pearson correlation coefficient between the two sets of ratios for each day of the May through September period.

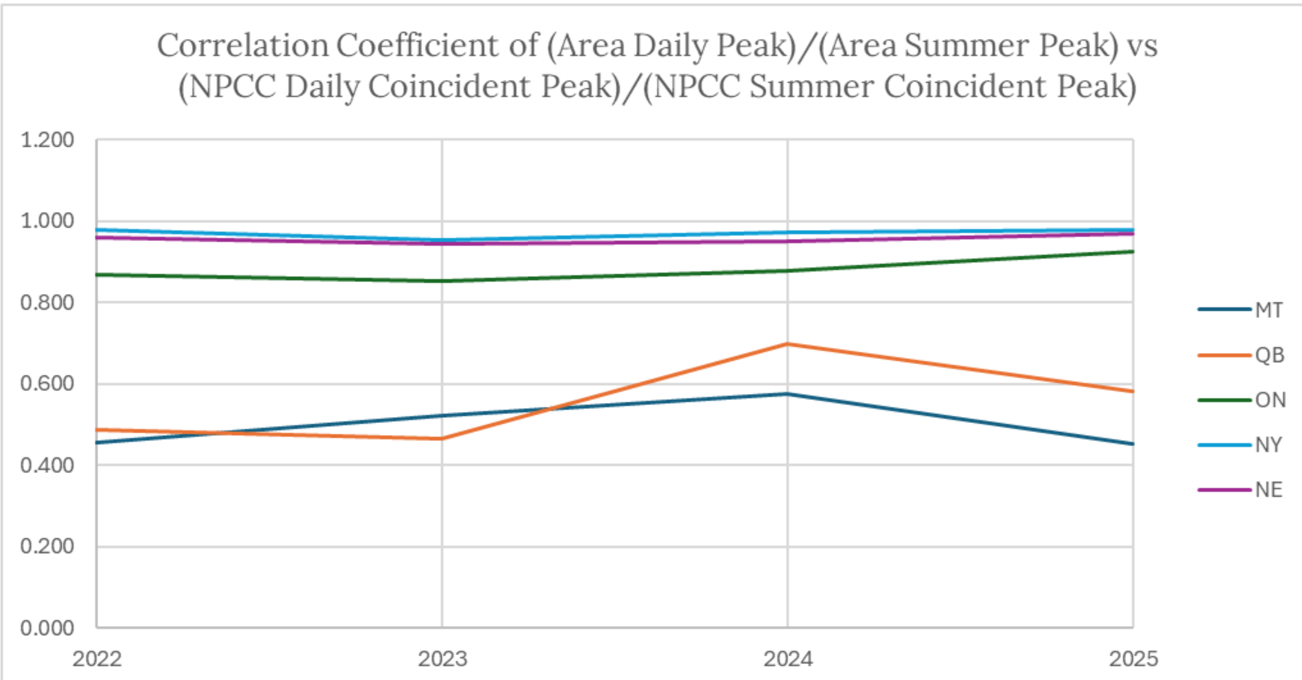

Figure 7-1: Comparison of Area Daily Peaks Correlation with NPCC Daily Peaks

8. 2026 Summer Reliability Assessments of Adjacent Regions

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

https://www.rfirst.org/resource-center/?_sft_resource_collection=studies-and-reports

For reviews of the other NERC Regional Entities and Assessment Areas, please go to:

http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

9. CP-8 2026 Summer Multi-Area Probabilistic Assessment Highlights

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 the May through September 2026 period. The assessment modeled the NPCC Region across a range of four scenarios. These scenarios include a Base Case scenario, conducted at both a 50/50 peak load level (50% chance of occurrence) and a higher peak load level (approximately 7% chance of occurrence), as well as a Severe Case scenario conducted at the same two peak load levels. The Severe Case scenario contains additional assumptions with Area specific low likelihood reduced resource conditions. Please refer to **Appendix VIII** (**Tables 9** and **10**) for a description of the Base Case and Severe Case Assumptions.

For each scenario, expected reliance on non-firm imports (external assistance) and expected operating procedure usage is estimated to meet demand. While a prescribed order of these operating procedures was used in this assessment, Areas may invoke these actions in any order, depending on conditions at the time. In this assessment, expected occurrences of less than 0.5 days per period are not considered significant.

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case scenario and 50/50 peak load forecast, no NPCC areas are expected to implement their operating procedures during the summer of 2026. The Maritimes, New England, and New York show a likelihood of relying on non-firm imports to meet peak demands.

Higher Peak Load Levels

Under higher peak load levels, the Maritimes, New England, and New York show a likelihood of activating their operating procedures in addition to relying on non-firm imports to meet peak demands. For all three Areas, this expected operating procedure usage includes a reduction of 30-minute reserves. Additionally, the Maritimes and New York show a likelihood of initiating interruptible loads. New York also exhibits an expected likelihood of implementing voltage reduction, reducing 10-minute reserves, and initiating public appeals to meet these elevated peak load demands.

Severe Case Scenario Summary

50/50 Peak Load Level

Under the Severe Case scenario and 50/50 peak load forecast, only New England and New York are expected to rely on their operating procedures, though the Maritimes shows a likelihood of relying on non-firm imports to meet peak demands. New England and New York demonstrate a likelihood of reducing 30-minute reserves and activating demand response resources.

Higher Peak Load Levels

The Severe Case scenario and higher peak load levels represents the most conservative scenario modeled in this probabilistic assessment, combining reduced resource conditions with higher-than-expected demand. Under this scenario, the results of this analysis indicate a risk of Loss of Load Expectation (LOLE) during the summer months for New York and New England. Strategies and procedures are in place to manage potential operational challenges and emergencies as they arise.

All five NPCC Areas show a likelihood of relying on external assistance at various times during these assumed conditions. While it is feasible for widespread weather patterns to cause higher-than-expected demand across the entire NPCC footprint, it is unlikely that the reduced resource condition assumptions associated with the Severe Case scenario will affect all five NPCC Areas simultaneously.

Québec

The Québec Area is not expected to require use of their operating procedures designed to mitigate resource shortages during the Summer of 2026. The Québec Area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of cumulative LOLE,[38] Loss of Load Hours (LOLH),[39] or Expected Unserved Energy (EUE)[40] risks over the summer May – September period for all the scenarios modeled.

LOLH and EUE can provide insight on system reliability because of their ability to measure loss of load duration and magnitude. EUE is helpful in quantifying the reliability risk impacts of weather or other natural events.

Ontario

The Ontario Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May – September period for all the scenarios modeled. Only the severe case scenario with reduced resources, higher peak load level conditions resulted in a significant amount of reliance on external assistance.

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38 LOLE: The expected number of days which contain an event in which system load is not served in a given time period.
39 LOLH: The expected number of hours which contain an event in which system load is not served in a given time period.
40 EUE: The expected amount of energy (MWh) that will not be served in a given time period.

New England

Under the Severe Case scenario and for the higher peak load levels, assuming low likelihood of reduced resource conditions (considering the impact of scheduled maintenance extended into the summer period and a 50% reduction in the import capabilities of external ties) the results indicated a negligible estimated cumulative LOLE risk (0.34 event-days/period), with associated LOLH (1.18 event-hours/period) and EUE (628 MWH/period) with the highest risk occurring in June and July, with some in August.

New York

Under the Severe Case scenario and for the higher peak load levels, assuming low likelihood of reduced resource conditions (assuming approximately 500 MW of extended maintenance in southeastern New York, a 630 MW reduction in cable transmission across HVDC facilities, and a 50% decrease in the effectiveness of demand response programs) the results indicated an estimated cumulative LOLE risk (0.66 event-days/period), with associated LOLH (2.00 event-hours/period) and EUE (1,255 MWh/period) with the highest risk occurring in August, with some risk occurring in June and July. Negligible cumulative LOLE risks were estimated over the summer May to September period for all other scenarios modeled.

Maritimes

The Maritimes Area is winter peaking and did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the summer May – September period for all the scenarios modeled. However, the results did show a reliance on external assistance in all four scenarios, with a minimum of 11.8 event-days/period in the base case expected load level conditions. Only the higher peak load scenarios demonstrate a notable use of operating procedures, including reducing 30-minute reserves and initiating interruptible loads.

Appendix I - Summer 2026 50/50 Load and Capacity Forecasts

Table AP-1 - NPCC Summary

Area NPCC
Revision Date May 6, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW [1]	Dispatchable DSM MW [2]	Total Capacity MW [3]	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Total Outages MW	Net Margin MW [4]	Net Margin %	Revised Net Margin MW [5]	Revised Net Margin %
3/May/26	160,033	-1	2,789	162,821	81,230	582	48,958	8,302	12,094	61,052	12,818	**15.8%**	12,818	**15.8%**
10/May/26	160,033	-1	2,789	162,821	83,900	583	46,159	8,313	12,135	58,294	12,896	**15.4%**	12,896	**15.4%**
17/May/26	160,033	-1	2,789	162,821	86,871	578	43,323	8,509	12,836	56,158	11,861	**13.7%**	11,861	**13.7%**
24/May/26	160,033	-1	2,789	162,821	91,100	585	40,063	8,549	12,241	52,304	11,453	**12.6%**	11,453	**12.6%**
31/May/26	158,405	883	3,049	162,337	97,891	586	35,881	8,483	10,195	46,076	10,473	**10.7%**	10,473	**10.7%**
7/Jun/26	158,405	850	3,049	162,304	100,667	588	33,511	8,534	10,451	43,962	9,728	**9.7%**	9,728	**9.7%**
14/Jun/26	158,405	850	3,049	162,304	102,144	583	33,607	8,656	10,384	43,992	8,096	**7.9%**	8,096	**7.9%**
21/Jun/26	158,405	850	3,099	162,354	103,357	583	30,336	8,706	12,414	42,750	8,124	**7.9%**	8,124	**7.9%**
28/Jun/26	158,430	850	3,049	162,329	103,275	581	30,560	8,393	12,938	43,498	7,744	**7.5%**	7,744	**7.5%**
5/Jul/26	158,430	783	3,049	162,262	104,679	582	28,264	8,361	12,995	41,259	8,544	**8.2%**	8,544	**8.2%**
12/Jul/26	158,420	783	3,049	162,252	105,062	586	28,344	8,250	12,890	41,234	8,292	**7.9%**	8,292	**7.9%**
19/Jul/26	158,420	783	3,049	162,252	104,495	589	29,002	8,762	12,883	41,884	7,699	**7.4%**	7,632	**7.3%**
26/Jul/26	158,420	783	3,049	162,252	103,820	588	28,230	8,617	12,890	41,120	9,284	**8.9%**	9,179	**8.8%**
2/Aug/26	158,420	783	3,049	162,252	104,452	583	29,647	8,528	13,068	42,716	7,140	**6.8%**	7,128	**6.8%**
9/Aug/26	158,420	783	3,049	162,252	104,194	581	29,341	8,544	12,634	41,976	8,119	**7.8%**	7,986	**7.7%**
16/Aug/26	158,420	783	3,049	162,252	104,161	592	30,493	8,620	12,140	42,633	7,428	**7.1%**	7,428	**7.1%**
23/Aug/26	158,420	783	3,049	162,252	103,687	599	31,605	8,824	12,000	43,605	6,734	**6.5%**	6,734	**6.5%**
30/Aug/26	158,420	783	3,049	162,252	102,703	595	32,634	8,749	11,996	44,631	6,764	**6.6%**	6,764	**6.6%**
6/Sep/26	158,470	783	3,049	162,302	100,197	586	30,746	8,677	12,491	43,237	10,776	**10.8%**	10,776	**10.8%**
13/Sep/26	158,470	783	3,049	162,302	100,262	592	31,477	8,657	11,871	43,348	10,627	**10.6%**	10,627	**10.6%**
20/Sep/26	158,470	783	3,049	162,302	91,773	593	35,669	8,706	11,320	46,989	15,427	**16.8%**	15,148	**16.5%**

Key

Highlighted week beginning 23-Aug-26 denotes the minimum forecasted NPCC “Revised Net Margin”.
Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand and minimum Revised Net Margin.
Highlighted week beginning 20-Sep-26 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

Area Maritimes
Revision Date April 21, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW [1]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
3/May/26	8,133	9	0	8,142	3,582	3,886	331	3,674	604	359	254	**7.1%**
10/May/26	8,133	9	0	8,142	3,525	3,886	332	3,744	604	359	243	**6.9%**
17/May/26	8,133	9	0	8,142	3,321	3,886	327	3,785	604	359	401	**12.1%**
24/May/26	8,133	9	0	8,142	3,377	3,886	334	4,051	604	359	86	**2.5%**
31/May/26	8,133	9	0	8,142	3,203	3,886	335	3,950	604	359	362	**11.3%**
7/Jun/26	8,133	-24	0	8,109	3,185	3,185	337	3,635	604	359	663	**20.8%**
14/Jun/26	8,133	-24	0	8,109	3,191	3,886	332	3,674	604	359	613	**19.2%**
21/Jun/26	8,133	-24	0	8,109	3,484	3,886	332	3,710	604	359	284	**8.1%**
28/Jun/26	8,133	-24	0	8,109	3,276	3,886	330	3,371	604	359	830	**25.3%**
5/Jul/26	8,133	-24	0	8,109	3,412	3,886	331	3,298	604	359	767	**22.5%**
12/Jul/26	8,133	-24	0	8,109	3,517	3,886	335	3,375	604	359	589	**16.7%**
19/Jul/26	**8,133**	-24	0	8,109	**3,421**	**3,886**	**338**	**2,666**	**934**	**359**	**1,067**	**31.2%**
26/Jul/26	8,133	-24	0	8,109	3,383	3,886	337	2,666	934	359	1,104	**32.6%**
2/Aug/26	8,133	-24	0	8,109	**3,465**	3,886	332	2,671	934	359	1,012	**29.2%**
9/Aug/26	**8,133**	-24	0	8,109	3,342	3,886	330	2,671	**934**	**359**	1,133	**33.9%**
16/Aug/26	8,133	-24	0	8,109	**3,528**	3,886	341	2,630	934	359	998	**28.3%**
23/Aug/26	**8,133**	-24	0	8,109	3,377	3,886	348	3,177	934	359	610	**18.1%**
30/Aug/26	8,133	-24	0	8,109	3,277	3,886	344	2,920	934	359	963	**29.4%**
6/Sep/26	8,183	-24	0	8,159	3,424	3,886	335	2,888	934	359	889	**26.0%**
13/Sep/26	8,183	-24	0	8,159	3,563	3,886	341	2,888	934	359	757	**21.2%**
20/Sep/26	8,183	-24	0	8,159	3,691	3,886	342	2,238	934	359	1,279	**34.7%**

Key

Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 20-Sep-26 denotes week with the largest forecasted NPCC "Revised Net Margin".

Highlighted number denotes forecasted Summer 2026 Peak Load for Maritimes.

Notes

(1) Known Maint./Derate include wind.

(2) Week beginning 20-Sep-26 denotes the forecasted Maritimes Summer 2026 Peak Week.

Table AP-3 – New England

Area ISO-NE
Revision Date May 6, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW [2]	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW [3]	Highest Experienced Load	Interruptible Load MW [4]	Known Maint./Derat. MW [5]	Req. Operating Reserve MW [6]	Unplanned Outages MW [7]	Net Margin MW	Net Margin %
3/May/26	29,945	409	277	30,631	15,738	28,130	0	9,079	2,062	3,400	352	2.2%
10/May/26	29,945	409	277	30,631	18,794	28,130	0	6,058	2,062	3,400	317	1.7%
17/May/26	29,945	409	277	30,631	19,668	28,130	0	4,521	2,062	3,400	980	5.0%
24/May/26	29,945	409	277	30,631	20,479	28,130	0	4,116	2,062	3,400	574	2.8%
31/May/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
7/Jun/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
14/Jun/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
21/Jun/26	27,962	409	346	28,717	25,228	28,130	0	55	2,062	2,275	-903	-3.6%
28/Jun/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
5/Jul/26	27,962	409	346	28,717	25,228	28,130	0	124	2,062	2,275	-972	-3.9%
12/Jul/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
19/Jul/26	**27,962**	409	346	28,717	25,228	**28,130**	**0**	**42**	2,062	2,275	-890	-3.5%
26/Jul/26	27,962	409	346	28,717	25,228	28,130	0	55	2,062	2,275	-903	-3.6%
2/Aug/26	27,962	409	346	28,717	25,228	28,130	0	55	2,062	2,275	-903	-3.6%
9/Aug/26	**27,962**	409	346	28,717	25,228	28,130	0	55	2,062	2,275	-903	-3.6%
16/Aug/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
23/Aug/26	**27,962**	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
30/Aug/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
6/Sep/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
13/Sep/26	27,962	409	346	28,717	25,228	28,130	0	42	2,062	2,275	-890	-3.5%
20/Sep/26	27,962	409	346	28,717	21,312	28,130	0	1,019	2,062	2,275	2,049	9.6%

Key

Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 20-Sep-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted numbers denote forecasted Summer 2026 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 2025-2026 capacity commitment period.
(2) Net Interchange includes peak purchases / sales from Maritimes, Quebec, and New York.
The Summer PLE period covers the months of June through September 13; developed to help mitigate the effects of abnormal weather during generator maintenance/outage scheduling
(3) 50/50 load forecast assumes net Peak Load Exposure (PLE) of 25,228 MW and does include 1,769 MW of behind-the-meter PV (BTM PV).
(4) On peak, 346 MW of Active Demand Capacity Resource (ADCR) is considered available for economic dispatch, which has been taken into account in Dispatchable DSM MW
(5) Includes known resource outages (scheduled and forced) as of the Revision Date listed above.
(6) 2,062 MW operating reserve assumes 115% of the largest contingency and 50% of the second largest contingency.
(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.

Table AP-4 – New York

Area NYISO
Revision Date April 14, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW [1]	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
3/May/26	37,534	1,918	1,415	40,867	22,576	33,956	1	9,101	2,620	2,440	4,131	**18.3%**
10/May/26	37,534	1,918	1,415	40,867	22,841	33,956	1	8,733	2,620	2,467	4,207	**18.4%**
17/May/26	37,534	1,918	1,415	40,867	25,646	33,956	1	7,033	2,620	2,591	2,978	**11.6%**
24/May/26	37,534	1,918	1,415	40,867	27,854	33,956	1	6,362	2,620	2,641	1,391	**5.0%**
31/May/26	37,534	1,918	1,415	40,867	29,078	33,956	1	5,073	2,620	2,735	1,362	**4.7%**
7/Jun/26	37,534	1,918	1,415	40,867	31,236	33,956	1	3,918	2,620	2,820	274	**0.9%**
14/Jun/26	37,534	1,918	1,415	40,867	31,578	33,956	1	4,384	2,620	2,786	-500	**-1.6%**
21/Jun/26	37,534	1,918	1,415	40,867	31,578	33,956	1	2,945	2,620	2,891	834	**2.6%**
28/Jun/26	37,549	1,918	1,415	40,882	31,578	33,956	1	3,195	2,620	2,874	616	**2.0%**
5/Jul/26	37,549	3,168	1,415	42,132	31,578	33,956	1	2,599	2,620	4,167	1,169	**3.7%**
12/Jul/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,866	2,620	4,147	912	**2.9%**
19/Jul/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,866	2,620	4,147	912	**2.9%**
26/Jul/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,866	2,620	4,147	912	**2.9%**
2/Aug/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,789	2,620	4,153	983	**3.1%**
9/Aug/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,813	2,620	4,151	961	**3.0%**
16/Aug/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,888	2,620	4,146	891	**2.8%**
23/Aug/26	37,539	3,168	1,415	42,122	31,578	33,956	1	2,822	2,620	4,150	953	**3.0%**
30/Aug/26	37,539	3,168	1,415	42,122	31,578	33,956	1	3,742	2,620	4,083	100	**0.3%**
6/Sep/26	37,539	3,168	1,415	42,122	31,578	33,956	1	3,089	2,620	4,131	705	**2.2%**
13/Sep/26	37,539	3,168	1,415	42,122	31,492	33,956	1	3,518	2,620	4,099	394	**1.3%**
20/Sep/26	37,539	3,168	1,415	42,122	27,554	33,956	1	5,961	2,620	3,920	2,068	**7.5%**

Key

Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 20-Sep-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Summer 2026 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.

Table AP-5 – Ontario

Area Ontario
Revision Date March 16, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW [2]	Highest Experienced Load	Interruptible Load MW	Known Maint./ Derat./Bottled Cap. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW [4]	Net Margin MW	Net Margin %
3/May/26	38,537	600	897	40,034	17,289	27,005	0	13,752	1,667	1,895	5,431	**31.4%**
10/May/26	38,537	600	897	40,034	17,279	27,005	0	15,381	1,667	1,909	3,798	**22.0%**
17/May/26	38,537	600	897	40,034	17,335	27,005	0	13,823	1,667	2,485	4,724	**27.2%**
24/May/26	38,537	600	897	40,034	18,675	27,005	0	13,300	1,667	1,841	4,550	**24.4%**
31/May/26	38,891	900	1,088	40,879	19,352	27,005	0	14,492	1,667	826	4,543	**23.5%**
7/Jun/26	38,891	900	1,088	40,879	19,854	27,005	0	12,685	1,667	997	5,676	**28.6%**
14/Jun/26	38,891	900	1,088	40,879	20,862	27,005	0	12,822	1,667	964	4,564	**21.9%**
21/Jun/26	38,891	900	1,138	40,929	21,820	27,005	0	12,287	1,667	2,888	2,268	**10.4%**
28/Jun/26	38,901	900	1,088	40,889	21,652	27,005	0	12,248	1,401	3,430	2,158	**10.0%**
5/Jul/26	38,901	900	1,088	40,889	22,331	27,005	0	11,272	1,401	3,444	2,441	**10.9%**
12/Jul/26	**38,901**	**900**	**1,088**	**40,889**	**22,519**	**27,005**	0	**11,372**	**1,401**	**3,359**	**2,239**	**9.9%**
19/Jul/26	38,901	900	1,088	40,889	22,610	27,005	**0**	11,394	1,401	3,351	2,133	**9.4%**
26/Jul/26	38,901	900	1,088	40,889	22,111	27,005	0	11,373	1,401	3,359	2,646	**12.0%**
2/Aug/26	38,901	900	1,088	40,889	21,691	27,005	0	11,673	1,401	3,531	2,593	**12.0%**
9/Aug/26	38,901	900	1,088	40,889	21,684	27,005	0	11,873	1,401	3,099	2,832	**13.1%**
16/Aug/26	38,901	900	1,088	40,889	21,600	27,005	0	12,174	1,401	2,610	3,105	**14.4%**
23/Aug/26	38,901	900	1,088	40,889	21,499	27,005	0	12,386	1,401	2,465	3,138	**14.6%**
30/Aug/26	38,901	900	1,088	40,889	21,172	27,005	0	11,979	1,401	2,529	3,809	**18.0%**
6/Sep/26	38,901	900	1,088	40,889	19,899	27,005	0	11,879	1,401	2,976	4,735	**23.8%**
13/Sep/26	38,901	900	1,088	40,889	19,591	27,005	0	12,590	1,401	2,388	4,919	**25.1%**
20/Sep/26	38,901	900	1,088	40,889	18,636	27,005	0	14,542	1,401	2,016	4,295	**23.0%**

Key
Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 20-Sep-26 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Summer 2026 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 19-Jul-26 denotes the Ontario Peak Week

Table AP-6 – Québec

Area Québec
Revision Date March 18, 2026

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
3/May/26	45,884	-2,937	200	43,147	22,045	23,052	250	13,352	1,350	4,000	2,650	**12.0%**
10/May/26	45,884	-2,937	200	43,147	21,462	23,052	250	12,243	1,361	4,000	4,331	**20.2%**
17/May/26	45,884	-2,937	200	43,147	20,901	23,052	250	14,161	1,556	4,000	2,779	**13.3%**
24/May/26	45,884	-2,937	200	43,147	20,715	23,052	250	12,234	1,596	4,000	4,852	**23.4%**
31/May/26	45,884	-2,353	200	43,731	21,030	23,052	250	12,324	1,531	4,000	5,096	**24.2%**
7/Jun/26	45,884	-2,353	200	43,731	21,164	23,052	250	13,231	1,582	4,000	4,004	**18.9%**
14/Jun/26	45,884	-2,353	200	43,731	21,284	23,052	250	12,685	1,703	4,000	4,309	**20.2%**
21/Jun/26	45,884	-2,353	200	43,731	21,247	23,052	250	11,339	1,753	4,000	5,642	**26.6%**
28/Jun/26	45,884	-2,353	200	43,731	21,541	23,052	250	11,704	1,706	4,000	5,030	**23.3%**
5/Jul/26	45,884	-3,670	200	42,414	22,130	23,052	250	10,971	1,675	4,000	3,888	**17.6%**
12/Jul/26	45,884	-3,670	200	42,414	22,220	23,052	250	10,689	1,563	4,000	4,192	**18.9%**
19/Jul/26	45,884	-3,670	200	42,414	21,659	23,052	250	12,034	1,745	4,000	3,226	**14.9%**
26/Jul/26	45,884	-3,670	200	42,414	21,520	23,052	250	11,270	1,600	4,000	4,274	**19.9%**
2/Aug/26	45,884	-3,670	200	42,414	22,490	23,052	250	12,459	1,511	4,000	2,204	**9.8%**
9/Aug/26	45,884	-3,670	200	42,414	22,362	23,052	250	11,929	1,527	4,000	2,846	**12.7%**
16/Aug/26	45,884	-3,670	200	42,414	22,227	23,052	250	12,759	1,603	4,000	2,075	**9.3%**
23/Aug/26	45,884	-3,670	200	42,414	22,005	23,052	250	13,178	1,807	4,000	1,674	**7.6%**
30/Aug/26	45,884	-3,670	200	42,414	21,449	23,052	250	13,951	1,732	4,000	1,532	**7.1%**
6/Sep/26	45,884	-3,670	200	42,414	20,068	23,052	250	12,848	1,660	4,000	4,088	**20.4%**
13/Sep/26	45,884	-3,670	200	42,414	20,388	23,052	250	12,439	1,640	4,000	4,197	**20.6%**
20/Sep/26	45,884	-3,670	200	42,414	20,580	23,052	250	11,909	1,689	4,000	4,486	**21.8%**

Key

Highlighted week beginning 12-Jul-26 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 20-Sep-26 denotes week with the largest forecasted NPCC “Revised Net Margin”.

Highlighted number denotes forecasted Summer 2026 Peak Load for Québec area.

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 definitions 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 Definitions

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. 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.

Individual Reliability Coordinator Area Definitions

Maritimes

A resource capable of being dispatched on demand that either provides energy or reduces demand. The Maritimes Area currently does not have any dispatchable demand side management that can be counted toward capacity.

Québec

Dispatchable demand side management is demand side management available for real-time dispatch by the control center. In short, it is the voltage reduction system. Its performance is updated annually.

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 normal Demand Forecast Methodology (**Appendix IV**).

Interruptible Loads

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

Individual Reliability Coordinator Area Definitions

Maritimes

Energy that can be interrupted by the System Operator to a Customer at any time for any duration under a contractual agreement.

Québec

Interruptible Load is the total of demand side management including interruptible industrial and commercial load and commercial and residential load reduction programs but excluding the voltage reduction system. The programs are called ahead of time in the short-term (same-day, day-ahead) planning horizons. There are fewer programs available in the summer than in the winter. Furthermore, the total interruptible load available to the system is significantly reduced this year with respect to previous years also. In part, this reflects an actual decrease in the available interruptible load. Also, the accounting related to one of the load contracts was corrected, also resulting in a decrease in available interruptible load.

Known Maintenance/Constraints

This is the reduction in Capacity caused by forecasted generator outages or derates and by any additional forecasted transmission outages or constraints causing internal bottling within the Reliability Coordinator area. Some Reliability Coordinator areas may include wind and solar generation derating.

Individual Reliability Coordinator Area Definitions

Maritimes

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

New England

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

New York

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

Ontario

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

Québec

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

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 10-minute and 30-minute reserve (fully available in 10 minutes and in 30 minutes).

Individual Reliability Coordinator Area Definitions

Maritimes

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

New England

The operating reserve requirement consists of 115% of the first largest contingency plus 50% of the second largest contingency.

New York

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

Ontario

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

Québec

The operating reserve requirement consists of 100% of the largest first contingency plus 50% of the second largest 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 consider a certain probability that some capacity may be on forced outage.

Individual Reliability Coordinator Area Definitions

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 natural gas-at-risk 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

It is based on the historical observation of the capacity that is on forced outage during the summer period from June 15 through September 15 in the last three years.

In the past, this value was significantly lower, because it was a provision for frequency regulation in Québec and for unplanned outages, but it also included the flexibility that Hydro-Québec had to postpone or recall planned outages. That flexibility is now included directly in the planned maintenance derating.

Net Margin

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

Individual Reliability Coordinator Area Definition

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.

New England

Net margin is the operable capacity margin for ISO-NE. The operable capacity margin is calculated in the monthly Current Year and First Future Year Annual Maintenance Schedule (AMS) report.

Bottled Resources

Bottled resources = Québec net margin + Maritimes net margin – available transfer capacity between Québec/Maritimes and the rest of NPCC.

Transmission bottling occurs during the summer capacity period when the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC.

Revised Net Margin (Table AP-1, NPCC Summary only)

Revised net margin = Net margin – Bottled resources

This is used in the NPCC assessment and follows from the Bottled Resources calculation.

Appendix III – Summary of Forecasted Summer Transfer Capabilities

The following table represents the forecasted transfer capabilities between Reliability Coordinator areas represented as Total Transfer Capabilities (TTC). It is recognized that the forecasted and actual transfer capability may differ depending on system conditions and configurations such as real-time voltage profiles, generation dispatch or operating conditions and may also account for Transmission Reliability Margin (TRM). 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**

  https://tso.nbpower.com/public/en/op/
  http://oasis.nspower.ca/en/home/oasis/default.aspx

- **New England**

  https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables

- **New York**

  http://mis.nyiso.com/public/
  https://oasis.nyiso.com/

- **Ontario**

  https://reports-public.ieso.ca/public/TxLimitsAllInService0to34Days/PUB_TxLimitsAllInService0to34Days.xml
  https://reports-public.ieso.ca/public/TxLimitsOutage0to2Days/
  https://reports-public.ieso.ca/public/TxLimitsOutage3to34Days/

- **Québec**

  https://www.oasis.oati.com/hqt/index.html

Transfers from Maritimes to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Québec			
Eel River/Matapédia, Madawaska	773	773	Eel River HVDC (capable of 350 MW) reduced by 2 MW due to losses. When Eel River converter losses and line losses to the Québec border are considered, Eel River to Matapédia transfer is 348 MW. Madawaska HVDC derated due to temperature. (350 MW @ 35 °C / 95 °F) plus available radial load transfers.
Total	**738**	**738**	
New England			
Orrington, Keene Road	1,000	1,000	For resource adequacy studies, NE assumes that it can import 1,000 MW of capacity to meet New England loads with 50 MW of margin for real-time balancing control.
Total	**1,000**	**1,000**	

Transfers from New England to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Maritimes			
Keswick (3001 line), Point Lepreau (390/3016 line)	550	550	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.
Total	**550**	**550**	
New York			
Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)	1,400	1,400	The transfer capability is dependent upon New England system load levels and generation dispatch. If key generators are online and New England system load levels are acceptable, the transfers to New York could exceed 1,200 MW. ISO-NE planning assumptions are based on an interface limit of 1,200 MW.
NNC Cable (Northport-Norwalk Harbor Cable)	200	200	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.
LI / Connecticut (CSC)	330	330	The transfer capability of the Cross Sound Cable (CSC) is 346 MW. However, losses reduce the amount of MWs that can actually be delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. The Cross Sound Cable is a DC tie and is not included in the feasible simultaneous transfer capability with NY.
Total	**1,930**	**1,930**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Québec			
Radisson-Nicolet (QC) / Sandy Pond (MA) (451 and 452 lines)	1,200	1,200	Export capability of the facility is 1,200 MW.
Highgate (VT) – Bedford (BDF) Line 1429	170	100	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 250 MW.
Derby (VT) – Stanstead (STS) Line 1400	0	0	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.
NECEC HVDC	0	0	NECEC is unidirectional from HQ to NE.
Total	**1,370**	**1,300**	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

Interconnection Point	TTC (MW)	ATC (MW)	Comments
New England			
Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)	1,600	1,400	New York applies a 200 MW Transmission Reliability Margin (TRM).
LI / Connecticut Northport-Norwalk Harbor Cable	200	200	
LI / Connecticut Cross-Sound Cable	330	330	Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY.
Total	**2,130**	**1,930**	
Ontario			
Lines PA301, PA302, BP76, PA27, L33P, L34P	1,600	1,300	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.
Total	**1,600**	**1,300**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
PJM			
PJM AC Ties	1,200	900	New York applies a 300 MW Transmission Reliability Margin (TRM).
NYC/PJM Linden VFT	315	315	
Total	**1,515**	**1,215**	
Québec			
Chateauguay (QC)/Massena (NY)	1,000	1,000	
Les Cédres (QC) / Dennison (NY)	100	100	
Astoria / Hertel (CHPE)	0	0	CHPE is unidirectional from HQ to NY.
Total	**1,100**	**1,100**	

Transfers from Ontario to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
New York			
Lines PA301, PA302, BP76, PA27, L33P, L34P	1,900	1,700	The TRM is 200 MW.
Total	**1,900**	**1,700**	
MISO Michigan			
Lines L4D, L51D, J5D, B3N	1,650	1,450	The TRM is 200 MW.
Total	**1,650**	**1,450**	
Québec			
NE / RPD – KPW Lines D4Z, H4Z	105	95	The 105 MW reflects an agreement through the TE-IESO Interconnection Committee. The TRM is 10 MW.
Ottawa / BRY – PGN Lines X2Y, Q4C	120	120	There is no capacity to export to Québec through Lines P33C and X2Y.
Ottawa / Brookfield Lines D5A, H9A	200	190	Only one of H9A or D5A can be in service at any time. The TRM is 10 MW.
Beauharnois (QC) / St-Lawrence (Ont.) Lines B5D, B31L	470	460	Capacity from Saunders that can be synchronized to the Hydro-Québec system. The TRM is 10 MW.
HAW / OUTA Lines A41T, A42T	1,250	1,230	The TRM is 20 MW.

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Total	**2,145**	**2,095**	
MISO Manitoba, Minnesota			
NW / MAN Lines K21W, K22W	300	275	The TRM is 25 MW.
NW / MIN Line F3M	150	130	The TRM is 20 MW
Total	**450**	**405**	

Transfers from Québec to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Maritimes			
Matapédia (QC)/Eel River (NB)	1200	1080	TTC/ATC can be reduced because of the thermal limits of the converters and the radial load transfer at Edmundson and Eel River. ATC includes the TRM which is reduced by 10% to account for load in the Gaspésie region
Total	**1,200**	**1,080**	Radial load transfer amount is dependent on local loading and is updated monthly and reviewed annually.
New England			
Radison-Nicolet (QC) / Sandy Pond (MA)	2,000	2,000	Capability of the facility is 2,000 MW.
Bedford (BDF) – Highgate (VT) Line 1429	225	225	Capacity of the Highgate HVDC facility is 225 MW.
NECEC HVDC	1,200	1,200	
Stanstead (STS) – Derby (VT) Line 1400	62	62	Normally only 35 MW of load in New England is connected.
Total	**3,537**	**3,537**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
New York			
Chateauguay (QC)/Massena (NY)	1,800	1,800	Beauharnois G.S. is used for Québec needs under peak load conditions, in which case transfer is limited to Châteauguay capacity (1000 MW).
Hertel/Astoria Annex	1,250	1,250	TTC for export only as measured at Astoria.
Les Cèdres (QC)/Dennison (NY)	279	279	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 279 MW and 160 MW respectively. However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.
Total	**3,329**	**3,329**	
Ontario			
Les Cèdres (QC)/Cornwall (Ont.)	160	160	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 199 MW and 160 MW respectively. However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.
Beauharnois (QC)/St-Lawrence (Ont.)	800	800	Beauharnois Generating Station is used for Québec needs under peak load conditions in which case no export is expected on this path at peak time.
Brookfield/Ottawa (Ont.)	250	250	Only one of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A.
Rapide-des-Iles (QC)/Dymond (Ont.)	85	85	This represents Line D4Z capacity. There is no capacity to export to Ontario through Line H4Z.
Bryson-Paugan (QC)/Ottawa (Ont.)	385	385	Limitations on the Québec system under peak load conditions restrict deliveries as follows P33C - 320 MW and X2Y – 65 MW. There is no capacity to export to Ontario through Line Q4C.
Outaouais (Qc)/Hawthorne (Ont.)	1,250	1,250	HVDC back-to-back facility at Outaouais.
Total	**2,930**	**2,930**	

Import Transfers from Regions External to NPCC

Interconnection Point	TTC (MW)	ATC (MW)	Comments
MISO (Michigan) / ONT			
Lines L4D, L51D, J5D, B3N	1,700	1,500	The TRM is 200 MW.
Total	**1,700**	**1,500**	
MISO (Manitoba-Minnesota) / ONT			
NW / MAN Lines K21W, K22W	260	235	Flows into Ontario include flows on circuit SK1 of 68 MW. The TRM on the K21W, K22W interface is 25 MW.
NW / MIN Line F3M	100	80	The TRM is 20 MW.
Total	**468**	**423**	
PJM / New York			
PJM AC Ties	1,200	900	The TRM is 300 MW.
PJM/NYC Linden VFT	315	315	
PJM/Long Island Neptune Cable	660	660	
PJM/NYC HTP DC/DC Tie	660	660	
Total	**2,835**	**2,535**	

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 Administrator). 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 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 based 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% and 9% (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models. The Maritimes uses 10% as the 90/10 Load Forecast Margin.

Above 90/10 load forecast values are estimated using the Long-Term Load Forecast High/Low Sensitivities modelling and the minimum temperatures for each month from the past 20 years.

New England

ISO-NE's long-term forecast[41] is developed using hourly simulations of four load components: base load, Electric Vehicle (EV) charging, Heat Pump (HP) utilization, and demand reductions associated with Behind-the-Meter Solar Photovoltaics (BTM PV). Hourly simulations of each load component are developed independently using consistent weather and calendar assumptions. Seventy years of climate-adjusted weather data are used as the basis of all simulations performed for each forecast year and reflect annual incremental warming for each year over the forecast horizon.

ISO New England's CELT contains a long-term load forecast that is a 10-year projection of gross and net load for each of the six states and the New England region. The base load forecast models gross load (net load with estimated BTM PV demand reductions added back) using hourly models supported by a daily energy model, for each of the region's eight load zones. Trend variables are developed and incorporated into the base load modeling to capture the effects of economics, energy efficiency, and other factors causing structural changes in either weather-sensitive or non-weather sensitive load. As a result, base load simulations reflect the demand net of these effects.

EV and HP forecasts are developed based on adoption projections that are used for subsequent hourly profiling of assumed penetration levels, weather, and calendar conditions. EV and HP adoption forecasts are developed for each county using recent adoption trends and policy considerations. Hourly EV demand modeling is based on expected charging patterns associated with five vehicle types and weather-adjusted battery efficiency curves. Hourly HP demand modeling is performed for both space and water heating applications within the residential and commercial sectors.[42]

BTM PV forecasts are developed based on adoption projections that are used for subsequent hourly profiling of assumed penetration levels and weather conditions. The BTM PV forecast includes projections of PV adoption based on agent-based modeling using assumed capital costs, retail rates, and federal and state Distributed Energy Resource (DER) policy incentives.[43]

Hourly loads for each of the four component forecasts are simulated using 70 years of climate-adjusted historical weather for each forecast year and are summed to yield the hourly gross and net load. Both net and gross forecasts include the expected impacts of EVs and HPs, and net forecasts result from subtracting BTM PV from gross forecasts. Forecasts are hierarchical in nature, with ISO-NE forecasts resulting from the sum of hourly

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41 Additional information describing ISO New England's load forecasting may be found at https://www.iso-ne.com/system-planning/system-plans-studies/celt, http://www.iso-ne.com/system-planning/system-forecasting/load-forecast, and https://www.iso-ne.com/committees/reliability/load-forecast.
42 Additional information describing ISO New England's electrification forecasts can be found at https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Electrification%20Forecasts.
43 Additional information describing ISO New England's BTM PV forecast can be found at https://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast.

simulations for all eight load zones, such that a diversity of weather and load characteristics can be represented. A waterfall method is used to quantify the peak impacts of each component of load. “50/50” and “90/10” gross, EV, HP, BTM PV, and net peak demand forecasts are associated with the 50th and 90th percentiles of the distribution of simulated seasonal peaks, respectively.

From a short-term load forecast perspective, ISO New England has deployed an enhanced version of the Irton MetrixND Zonal load forecast, which produces a “BTM PV aware” zonal load forecast for the eight individual New England load zones six days in advance through the current operating day. This forecast improves reliability on a zonal level by considering not only different weather from zone to zone but also different BTM PV generation from zone to zone. An example would be when the Boston zone has a forecast temperature of sixty-five degrees and modest BTM PV generation, while the Hartford area has a forecast of ninety degrees with high BTM PV generation. This zonal forecast helps ensure 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 a suite of multi-platform load forecast regional models, including Matlab, LGBM, Artificial Neural Network models (ANNSTLF), Similar Day Analysis (SimDays) and other Itron MetrixND models[44.]

New York

NYISO conducts load forecasting for the NYCA and for localities within the NYCA. NYISO employs a multi-stage process to develop load forecasts for each of the eleven zones within the NYCA. 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 miscellaneous 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 building codes and appliance standards. Economic variables considered include Gross Domestic Product (GDP), number of households, population, and commercial and industrial employment. Projected long-term weather trends from the NYISO Climate Change Impact Study Phase I are included in the end-use models. In the second stage, the incremental impacts of additional policy-based energy efficiency, behind-the-meter solar PV and distributed generation are deducted from the forecast; and the incremental impacts of electric vehicle usage and building electrification are added to the forecast. Projected load increases due to interconnecting large load projects are added to the forecasts. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of behind-the-meter

44 See: ISO-NE Forecast and Scheduling, Reserve Adequacy Analysis.

energy storage resources are deducted from the peak forecasts. In the final stage, the NYISO aggregates load forecasts by zone.

Forecasts are based on information obtained from the New York State Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), state power authorities, Transmission Owners, the U.S. Census Bureau, the U.S. Energy Information Administration, Moody's Analytics, and Itron. The baseline forecast reflects a combination of information provided by Transmission Owners for their respective territories and forecasts prepared by NYISO.

In addition to the baseline forecast, NYISO also produces high and low forecasts for each zone that represent 90/10 and above 90/10 forecasts set at 99th percentile 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 baseline 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.

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 relationship between electricity demand and numerous drivers. These drivers include weather variables, economic data, conservation savings, embedded generation output, embedded generation capacity and calendar variables. Using regression techniques, the models estimate the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy, minimum and peak demand, including zone and system wide projections. The 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 economic assumptions and historic weather data. The demand models use population projections, labor market drivers and industrial indicators 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 behavior (including the impact of smart meters).

The IESO estimates distribution connected solar and wind generation output, and in turn, the demand for grid supplied electricity by using historical weather, global horizontal irradiance and wind speed data across a wide geographic area. The models solve by using coincidental weather inputs to determine embedded generation output and grid demand. For the forecast period, the models use historical weather data from the last 31 years along with shifting that weather plus/minus seven days to have weather interact with the calendar. The result is 465 simulated values (31 years x 15 daily shifts) for each hour, 465 simulated daily peaks for each day, 465 simulated weekly peaks for each week and 465 simulated monthly peaks for each month.

For this report, the laminations from the weekly distributions are used to populate the report. For each week, the median weekly peak (50/50), the 90th percentile (90/10) and the "above 90/10" value - represented by the weekly peaks at the 99th percentile (99/01) – are included in the respective columns of the spreadsheet.

The weekly peak demands are derived from the distribution of weekly peaks generated from the 465 simulations. Likewise, the monthly peaks are similarly derived from the 465 simulations. The monthly median peaks (50/50) are used to assess seasonal adequacy needs and are not the same equivalent to the weekly peaks as the monthly peaks are generated from a larger dataset. Therefore, the weekly median peaks reported in this report are used for operational planning; they will not be the same as the seasonal peaks reported in other reports such as the IESO's Reliability Outlook.

In Ontario, demand management programs include demand response, dispatchable loads, interruptible loads and residential load management programs. Historical data is used to determine the quantity of reliably available capacity, which is treated as a resource to be dispatched.

For determining wind and solar derating factors, Ontario uses seasonal contribution factors based upon median historical hourly production values.

Québec

Hydro-Québec's demand and energy-sales forecasting is built upon the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on a 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 54-year temperature database (1971–2024), adjusted by 0.30°C (0.54°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 378 different demand scenarios. Weather uncertainty is calculated from these demand scenarios (energy and peak). Load uncertainty is due to the uncertainty in economic and demographic variables affecting demand forecast and to residual errors from the models.

Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty. This overall uncertainty is lower during the summer than during the winter. For example, at the summer peak, weather conditions uncertainty is about 450 MW, equivalent to one standard deviation. During winter, this uncertainty is about 1,500 MW.

The Québec system operator then determines the Québec Balancing Authority Area forecasts using Hydro-Québec's forecasts (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. Hydro-Québec 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 No. 1 – "Design and Operation of the Bulk Power System"

Description: Directory No. 1 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 No. 2 – "Emergency Operations"

Description: Directory No. 2 provides 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 No. 5 – "Reserve"

Description: Directory No. 5 provides objectives, principles, and requirements to enable each NPCC Reliability Coordinator Area to provide reserve and simultaneous activation of reserve.

NPCC Regional Reliability Reference Directory No. 6 – "Reserve Sharing Groups"

Description: Directory No. 6 provides the framework for Regional Reserve Sharing Groups within NPCC. It establishes the requirements for any Reserve Sharing Groups involving NPCC Balancing Authorities.

NPCC Regional Reliability Reference Directory No. 8 – "System Restoration"

Description: Directory No. 8 provides objectives, principles, and requirements to enable each NPCC Reliability Coordinator Area to perform power system restoration following a major event or total blackout.

A-10 "Classification of Bulk Power System Elements"

Description: This Classification of Bulk Power System Elements (Document A-10) provides the methodology for the identification of those elements of the interconnected NPCC Region to which NPCC bulk power system criteria are applicable. Each Reliability

Coordinator Area has an existing list of bulk power system elements. The methodology in this document is used to classify elements of the bulk power system and has been applied in classifying elements in each Reliability Coordinator Area as bulk power system or non-bulk power system.

NPCC Procedures Pertinent to Operations

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

Description: The C-01 procedure 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: The C-15 procedure 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 C-43 procedure provides the procedure to be followed in conducting operations reviews of new facilities being added to the power system. This procedure is intended to apply to new facilities that, if removed from service, may have a significant, direct, or indirect impact on another Reliability Coordinator area's inter-Area or intra-Area transfer capabilities. The cause of such impact might include stability, voltage, and/or thermal considerations.

Appendix VI – Web Sites

Independent Electricity System Operator

http://www.ieso.ca/

ISO-New England

http://www.iso-ne.com

Maritimes

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

Midwest Reliability Organization

https://www.mro.net/

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

Hydro-Québec

http://www.hydroQuébec.com

Appendix VII – References

For historical NPCC Reliability Assessments, please visit:

https://www.npcc.org/reliability-services?category=Seasonal%20Assessment

Appendix VIII – CP-8 2026 Summer Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment for Summer 2026

NPCC TFCP and TFCO Approved on May 18, 2026
Conducted by the NPCC CP-8 Working Group

Final Report – Public – June 10, 2026

CP-8 Working Group

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TABLE OF CONTENTS

Foreword

The Champlain Hudson Power Express (CHPE), which is a 1,250 MW High-Voltage Direct Current (HVDC) transmission project, was assumed to be available to deliver power from Québec directly to New York City for the entire probabilistic assessment period.

The New England Clean Energy Connect (NECEC) is a 1,200 MW HVDC tie between Québec and New England and was not modeled in this probabilistic assessment since it is not supported by a firm capacity supply contract.

1. Executive Summary

This report, prepared by the CP-8 Working Group, estimates the use of the available NPCC Area operating procedures to mitigate resource shortages from the May through September 2026 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 simulations.

The assumptions used in this probabilistic study are largely consistent with the CO-12 Working Group's study, "NPCC Reliability Assessment for Summer 2026", May 2026[45] and summarized in **Table 1**.

Area	50/50 Peak[46] (MW)	Higher Peak[47] (MW)	Available Capacity[48] (MW)	Peak Month
Québec (HQ)	22,761	25,330	35,250	August
Maritimes Area (MT)	3,681	4,019	7,742	May
New England (NE)	25,238[49]	27,987	29,276[50]	June
New York (NY)	31,990	34,552	37,769	June
Ontario (ON)	23,974	26,730	36,912	July

Table 1: Assumed Load and Base Case Capacity for Summer 2026

The study modeled the load forecast as a probability distribution having seven levels. Shown in **Table 1** are the values associated with the 50/50 peak load level (based on each Area's projection of mean demand) and a higher peak load level associated with the top two load levels of the seven levels simulated in this assessment (see **Table 5**). The 50/50 peak load level shown has a 50 percent chance of occurring. The higher peak load level shown has a seven percent chance of occurring. While the higher peak load level, as defined for this study,

45 See: Reliability Services | NPCC
46 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 is based on the 2026 CELT forecast that takes into account the impact from behind-the-meter PV load reduction. The New York ISO peak value includes the impacts of Behind-the-Meter: Net Generation resources.
47 The higher peak load forecast is determined as a weighted average of the forecasted values two and three standard deviations higher than the mean, which has approximately a seven percent probability of occurrence.
48 Available Capacity represents Area's effective capacity at the time of the peak; it takes into account firm imports and exports, reductions due to deratings, Active Demand Response, and scheduled outages. New England capacity includes active demand capacity resources and net capacity imports. New York capacity includes SCR resources and imports.
49 This is the gross peak forecast with peak reduction impacts from BTM PV added in. Gross peak = 26,997 MW; BTM PV reduction = 1,759; modeled net peak = 25,238 MW. Note that the 2026 CELT also includes a new component reflecting BTM BESS, that is not included here. As a result, the net peak listed in this table is about 10 MW higher than that included in the 2026 CELT.
50 Total generation = 29,276 MW + Active DR (492 MW) + Net import (234 MW) = 30,003 MW (Net).

may be different for NPCC Areas in their own studies, the Working Group (WG) finds this higher peak load level appropriate for providing an assessment of a range of conditions within NPCC. Details of information provided by each Area for the forecasts are presented in **Chapter 3** (Study Assumptions), **Table 4** and **Figure 1** of this report.

For the probabilistic load forecast levels 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 **Tables 9** and **10** of this report.

Table 2 shows the estimated use of demand response programs and operating procedures under the Base Case assumptions for the 50/50 peak load and the higher peak load levels for the May - September 2026 period.

The 50/50 peak load results were based on the probability-weighted average of all seven load levels simulated. The higher load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring. Occurrences greater than 0.5 days/period are highlighted.[51]

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Higher Load Level				
External Assistance Calls	0.048	11.806	0.738	0.510	0.0120	0.724	28.598	4.084	4.772	0.162
Activation of DR/SCR	0.002	-	-	0.353	0.000	0.029	-	-	3.172	0.000
Reduce 30-min Reserve	-	0.151	0.057	0.309	-	-	0.964	0.583	2.738	-
Initiate Interruptible Loads/Voltage Reduction[52]	-	0.082	0.013	0.108	-	-	0.551	0.169	1.159	-
Reduce 10-min Reserve[53]	-	0.001	0.007	0.050	-	-	0.007	0.086	0.606	-
Appeals	-	-	0.006	0.043	-	-	-	0.078	0.548	-
Disconnect Load	-	-	0.001	0.017	-	-	-	0.016	0.223	-

Table 2: Expected Use of the Operating Procedures under Base Case Assumptions (event-days/period)

Under the Base Case Scenario, NPCC Areas are unlikely to face resource shortages exceeding a cumulative likelihood greater than 0.5 days per period of needing to implement their operating procedures for the expected (50/50) peak load forecast (representing the

51 Rounded to the nearest whole occurrence, likelihoods of greater than 0.5 days/period are considered as an occurrence.
52 Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
53 New York initiates Appeals prior to reducing 10-min Reserve.

probability weighted average of all seven load levels). The Maritimes, New England, and New York will likely depend on non-firm imports from their neighboring areas to mitigate any resource shortages.

Under the Higher Load Levels, the cumulative likelihood of activating emergency procedures increases considerably due to anticipated resource constraints. The Maritimes, New England and New York Areas show a notable likelihood of utilizing their operating procedures, including reducing 30-minute reserves in addition to relying on external assistance to address resource shortages. The Maritimes also shows a notable likelihood of activating interruptible loads. New York demonstrates a higher cumulative likelihood of relying further on their operating procedures to mitigate potential resource shortages. These procedures included activating demand response, reducing 10-minute reserves, as well as activation of interruptible loads and public appeals to maintain system reliability during the upcoming summer period.

Table 3 presents the estimated increased use of operating procedures under the Severe Case Scenario assumptions for both the expected 50/50 peak load level and the higher peak load levels during the May–September 2026 period. Occurrences greater than 0.5 days/period are highlighted.[54]

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Higher Load Level				
External Assistance Calls	0.214	17.576	1.362	1.001	0.060	3.091	42.781	5.771	6.962	0.683
Activation of DR/SCR	0.022	-	-	0.840	0.002	0.332	-	-	5.842	0.030
Reduce 30-min Reserve	-	0.462	0.610	0.785	-	0.002	2.687	3.119	5.386	0.009
Initiate Interruptible Loads/Voltage Reduction[55]	-	0.258	0.235	0.273	-	-	1.502	1.468	2.569	0.002
Reduce 10-min Reserve[56]	-	0.003	0.154	0.145	-	-	0.023	1.053	1.485	0.002
Appeals	-	-	0.153	0.124	-	-	0.001	1.034	1.341	-
Disconnect Load	-	-	0.039	0.055	-	-	0.001	0.343	0.655	-

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

Under the Severe Case scenario, characterized by low likelihood of reduced resource conditions, the Maritimes, New England, and New York have increased levels of reliance on external assistance to maintain reliability during the expected 50/50 peak load forecast.

54 Rounded to the nearest whole occurrence, likelihoods of greater than 0.5 days/period are highlighted.
55 Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
56 New York initiates Appeals prior to reducing 10-min Reserve.

Both New York and New England area show a likelihood exceeding 0.5 days per period of needing to implement operating procedures —such as activating their demand response and reducing 30-minute reserves — during the summer of 2026.

Under the Severe Case scenario, assuming low likelihood of reduced resource conditions for the higher peak load levels, the results indicate a risk of Loss of Load Expectation (LOLE) during the summer months for New York and New England. New England and New York demonstrate a greater cumulative likelihood of implementing their operating procedures to address resource shortages. These outcomes are primarily driven by forecasted demand levels and associated reserve margin expectations. These higher peak load conditions represent a combined probability of approximately 7%, highlighting potential risks under rare but severe system stress events.

The NPCC 2026 Summer Probabilistic Risk Assessment included a sensitivity analysis to determine if a potential delay of the 1,250-MW Champlain Hudson Power Express (CHPE) would have a significant impact on system reliability. While the base case assumed that CHPE was expected to begin operations on May 1, the sensitivity case assumed that CHPE would not be available throughout the 2026 summer operating period. The analysis verified that reliability is maintained by retaining the Gowanus 2 and 3 and Narrows 1 and 2 generators, consistent with NYISO contingency plans and the New York State peaker rule. Detailed results are included in **Appendix H** of this report.

Additionally, the 2026 Summer Reliability Assessment also included a separate independent sensitivity analysis to evaluate resource adequacy within the Northern New York (NNY) load pocket under extreme stress. This study assessed the impact on the New York Control Area (NYCA) and the entire NPCC region during a simultaneous loss of intermittent renewables, specific thermal peaker plants, and non-firm imports. To simulate this "worst-case" scenario, the model assumed zero local wind and solar output—mimicking a localized intermittent resource unavailability for all hours—alongside the unavailability of the Saranac Energy and Sithe-Massena units and a total loss of imports across the Cedar Rapids interface.

Results indicated only minor reliability impacts for both New York and neighboring NPCC regions, demonstrating that the system has sufficient resilience to absorb these specific resource losses. Furthermore, the analysis confirmed that reliability risks during these extreme conditions do not significantly alter overall energy deliverability. While there may be localized effects if this scenario were to occur, the New York system still remained below the 0.5 event-days/period threshold for both expected and higher load conditions. **Table 11** provides a detailed overview of the assumptions used in this sensitivity analysis, while detailed results are included in **Appendix H** of this report.

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 2026.

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 assumptions used in this probabilistic study are consistent with the NPCC CO-12 Working Group's development of the NPCC Reliability Assessment for Summer 2026, May 2026. The CP-8 Working Group's Objective, Scope of Work, and 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 probabilistic simulations. **Appendix E** provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 5.10.4171 was used for this reliability assessment.

3. Study Assumptions

The database developed by the CP-8 Working Group for the *NPCC 2025 Long Range Adequacy Overview*[57] was used as the starting point for this reliability analysis. Working Group members reviewed the existing data and revised to reflect system conditions expected for the 2026 summer period.

3.1 Demand

3.1.1 Load Assumptions

Each area provided annual or monthly peak and energy forecasts for 2026 Summer. **Table 4** summarizes each Area's summer 50/50 peak load level assumptions for the study period.

Area	Month	Peak Load (MW)
Québec	August	22,761
Maritimes Area	May	3,681
New England	June	25,238[58]
New York	June	31,990
Ontario	July	23,974

Table 4: Assumed NPCC Areas 2026 50/50 Summer Peak Demand

Specifics related to each Area's 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 uncertainty factors were developed by applying statistical methods to a comparison of historical forecast values of load to the actual loads experienced.

New England

The 2026 CELT gross 50/50 summer peak demand forecast is 26,997 MW for the summer of 2026. This gross summer peak demand reflects a forecast of peak demand for the New England system, which implicitly accounts for the reductions from energy efficiency programs but does not reflect behind-the-meter PV (BTM PV) or behind-the-meter BESS

57 2025 NPCC Long Range Adequacy Report.
58 This is the CELT 2026 50/50 gross peak load minus Behind-the-Meter PV for the summer of 2026. This is the same load modeled in GE MARS. ISO-NE provides BTM PV as separate profiles for the NPCC probabilistic assessment.

(BTM BESS). The 2026 peak reduction from the BTM PV is 1,759 MW based on the 2026 CELT report.

ISO New England's long-term energy model and seasonal forecast underwent methodology updates for CELT 2025. The procedure for generating load forecast uncertainty multipliers was updated to reflect this new load forecast methodology. In the updated methodology, LFU multipliers are calculated to fit MARS load to the CELT load distribution, which now includes multiple years of load scenarios. This updated methodology allows the modeled MARS load to reflect the CELT load distribution.

New York

The New York ISO employs a multi-stage process to develop 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 and standards. Economic variables considered include Gross Domestic Product, households, population, and commercial and industrial employment. In the second stage, the incremental impacts of additional policy-based energy efficiency, behind-the-meter solar PV and distributed generation are deducted from the forecast; and the incremental impacts of electric vehicle usage and other electrification are added to the forecast. The impacts of net electricity consumption of energy storage units due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of behind-the-meter energy storage units are deducted from the peak forecasts. In the final stage, the New York ISO aggregates load forecasts by Zone.

These forecasts are based on information obtained from the New York State Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), 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.[59]

59 See: Publications - NYISO.

Ontario

The Ontario IESO demand forecast for the CP-8 Working Group probabilistic assessment is consistent with the Ontario IESO Reliability Outlook published on March 19, 2026.[60]

Québec

The load forecast is consistent with the "2025 NPCC *Québec Interim Review of Resource Adequacy*."[61] The sales forecast represents the aggregation of the forecast of three sectors – domestic, commercial, and large industrial. The types of models used to forecast are different for each sector. Specifically, forecasts are based on statistically adjusted end-use and/or standard econometric models. They consider weather variables, economic indicators forecasts, demographics, demand side management, and different information about large industrial customers. This forecast is weather normalized and prospective effects of climate change are considered through the most recent Coupled Model Intercomparison Project (CMIP)[62] simulations.

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by modeling load factors for base load and evaluating contribution to peak from new end-uses/sectors (EVs, PV, etc.).

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a historical database of temperatures (1971 to present), adjusted to account for climate change using the most recent CMIP simulations. Moreover, each year of historical climatic data is shifted up to ±9 days to gain information on conditions that occurred during either a weekend or a weekday. The base case scenario is the arithmetical average of the peak hour in each of these 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.

3.1.2 Load Model in General Electric's Multi-Area Reliability Simulation (MARS) Program

Since the 2022 NPCC Summer Reliability assessment, the CP-8 Working Group has used the historical hourly load shape based on the summer of 2021 for the months of May – September. The selection of the summer hourly load shape assumption is re-evaluated on a periodic basis with the previous summer load shape. On a region-wide basis, the 2021 hourly

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60 See: Reliability Outlook. (Table 1.1.1).
61 See: 2025 NPCC Québec Interim Review of Resource Adequacy.
62 See: CMIP - Coupled Model Intercomparison Project.

load shape appears to be similarly stressful to the 2025 hourly load shape with an indication that the 2025 load shape produces a higher NPCC-wide coincident peak load.[63] However, the number of days above 95%, 90%, and 85% of the peak load for the 2025 shape are all lower when compared to the 2021 load shape. Almost all of the top 31 days for the 2021 load shape when normalized to the respective 2026 seasonal peak load is higher compared to the 2025 load shape. The CP-8 Working Group compared the results of this assessment for both the 2021 and 2025 hourly load shape assumptions, finding that the resulting loss of load and estimated operating procedure usage outcomes were higher for each of the NPCC Areas for the 2021 load shape. Consequently, the CP-8 WG recommends retaining the 2021 load shape as the standard basis for summer profiles in upcoming 2026 Reliability Assessments.

The loads for each Area were modeled on an hourly, chronological basis, using the 2021 hourly load shape. The MARS program modified the hourly loads through time to meet each Area's specified peaks and energies.

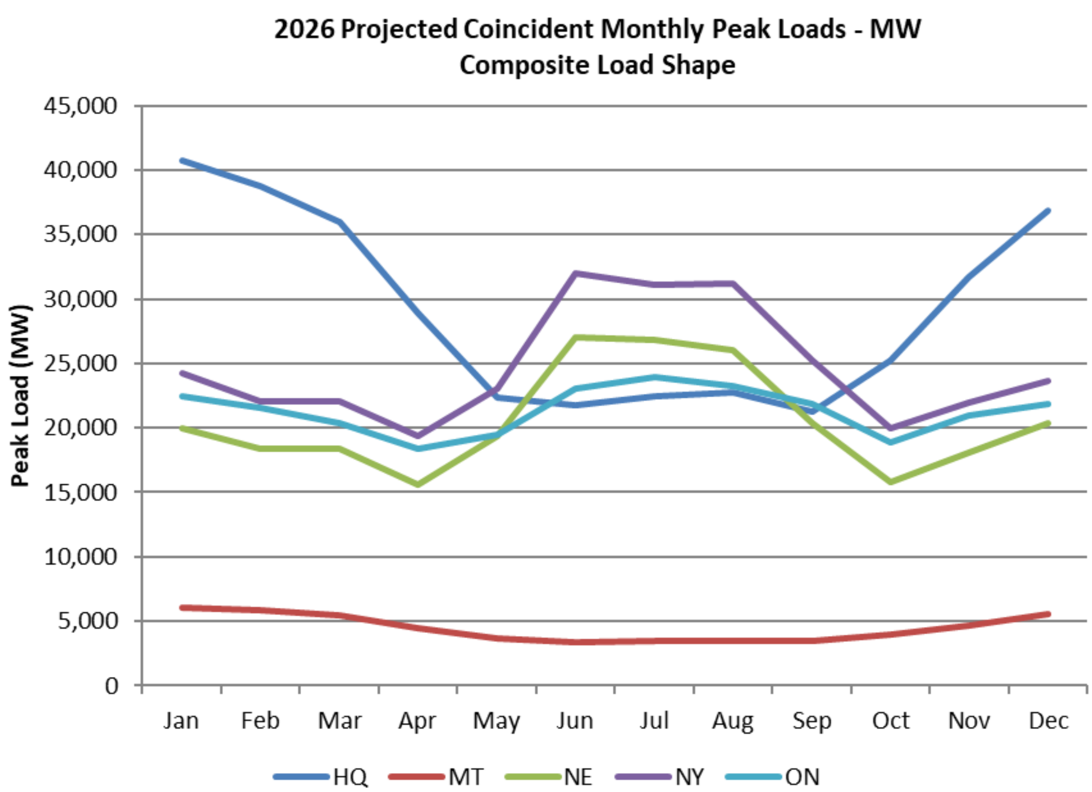

Figure 1: 2026 Projected Monthly Peak Loads for NPCC

The effects on reliability of uncertainties in the peak load forecast due to weather and/or economic conditions were captured through the load forecast uncertainty model within MARS. The program computes the reliability indices at each of the specified load levels and

63 See: NPCC Load Shape Analysis.

calculates weighted-average values based on input probabilities of occurrence. For this study, seven load levels were modeled based on the monthly load forecast uncertainty provided by each Area.

The NPCC Areas provide a projection for peak loads and energies that are modified by the 2021 load shape,[64] 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 seven peak load levels represent the expected 50/50 peak load level and one, two and three standard deviations above and below that 50/50 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 uncertainty affect all 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.

The indices for the higher peak loads provide a measure of the reliability in the event of higher-than-expected peak loads. The higher load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring. These values are highlighted in **Table 5**. For example, if the 50/50 Load July monthly peak load for Ontario is "y", then the Higher Load value assumed for that month based on **Table 5** would be calculated as y*1.120.[65]

Area	Per-Unit Variation in Load						
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 7
HQ	1.105	1.072	1.034	0.998	0.964	0.934	0.918
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.080	1.037	1.008	0.976	0.903	0.624	0.582
NY	1.119	1.080	1.036	0.989	0.940	0.888	0.833
ON	1.165	1.115	1.058	1.000	0.938	0.876	0.821
Probability of Occurrence	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 5: Per Unit Variation in Load-by-Load Level Assumed for Each Area's Peak Month

64 Ontario demands provided were already adjusted for 2021 weather.
65 As highlighted on **Table 5**. Probability weighted average of the top two load variations (1.165*{0.0062/ (0.0062+0.0606)} +1.115*{0.0606/ (0.0062+0.0606)} = 1.120).

The results for this study are reported for two peak load conditions: 50/50 and higher load levels. The values for the 50/50 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.

While the higher peak load, as defined for this study, may be different for NPCC Areas for their own studies, the Working Group finds these higher peak load levels are appropriate for a probabilistic reliability assessment for a range of conditions across the NPCC region.

3.2 Resources

Table 6 below summarizes the 2026 summer capacity assumptions for each of the NPCC Areas modeled in the analysis for the Base Case Scenario; the assumptions are largely consistent with the assumptions used in the NPCC CO-12 Working Group's, *NPCC Reliability Assessment for Summer 2026*, dated May 2026.

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

	HQ	MT	NE	NY	ON
Assumed Capacity[66]	35,250	7,735	29,276	37,769	36,249
Demand Response[67]	0	327	492	724	1,088
Net Imports/Exports[68]	-3,340	-122	234	3,038	900
Reserve (%)[69]	40.2	115.9	18.9	29.8	62.3
Scheduled Maintenance[70]	-[71]	1,935	0	0	17

Table 6: Resource Assumptions at Summer Peak - Base Case (MW)

Details regarding each NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent NPCC Review of Resource Adequacy.[72] The MARS modelling details for each type of resource in each Area are provided in **Appendix E** of the report. In addition, the following Areas provided the following:

66 Assumed Capacity - the total generation capacity assumed to be installed at the time of the summer peak.
67 Demand Response: the amount of "controllable" demand expected to be available for reduction at the time of peak. New York value represents the SCR amount. For New England, this represents the Active Demand Capacity Resources.
68 Net Imports / Exports: the amount of expected firm imports and exports at the time of the summer peak. The value is positive for imports and negative for exports.
69 Reserve = ((Capacity + Net imports + Demand Response) – Peak Load) / Peak Load.
70 Maintenance scheduled at time of peak.
71 Planned resources and load forecast consistent with the 2025 NPCC Québec Interim Review of Resource Adequacy for the summer 2026 period – the assumed capacity already includes scheduled maintenance and restrictions.
72 See: NPCC Area's Review of Resource Adequacy.

Maritimes

Planned outages forecast to occur during the period are reflected in this assessment.

New England

The generating resources include the existing units and planned resources that are expected to be available for the 2026 summer period.

Wind and solar generation

Wind and solar resources are modelled using five years of hourly output profiles, based on simulated resource output during 2021-2025. With every sample draw, MARS chooses at random one of the five profiles to use for that sample.

Each hourly output profile is scaled to Network Resource Capability (NRC). Larger resources use unique profiles, representing their simulated output over 2020-2024, while smaller resources use shared, aggregate profiles, calculated by Regional System Plan (RSP) zone.

All other generation

All other resources are modeled as thermal resources except Stand-alone batteries which are modeled as Energy Storage in GE MARS. The rating used for commercial resources is based on their Seasonal Claimed Capability. For non-commercial resources that are expected to become commercial during the study period, their Forward Capacity Market Capacity Supply Obligation is used. 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. The resources assumed in this assessment also include 492 MW of active demand capacity resources and 523 MW of firm capacity imports from the neighboring areas. These demand resources and firm imports are based on the Capacity Supply Obligations associated with the Annual Reconfiguration Auction conducted in 2025 for the 2026-2027 Capacity Commitment Period (CCP). [73]

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report entitled *Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2026–2027 Capability Year*, dated January 16, 2026,[74] and the *New York Control Area Installed Capacity Requirement for the Period May 2026-April 2027* New York State Reliability Council, December 05, 2025, report.[75]

73 The 2026-2027 CCP starts on June 1, 2026, and ends on May 31, 2027. Note that the modeled amount of imports is slightly below the capacity supply obligations associated with the Annual Reconfiguration Auction.
74 See: 2026-2027-LCR-Report-Final.
75 See: 2026-IRM-Study-Technical-Report.

Ontario

Generating unit availability was based on the Ontario IESO Reliability Outlook - An Adequacy Assessment of Ontario's Electricity System from April 2026 to September 2027, dated March 19, 2026.[76] Capacity acquired in the Ontario IESO's December 2025 capacity auction has added 1,833 MW of capacity for the summer of 2026 and 1,125 MW of capacity for winter 2026-2027.

Québec

The planned resources are consistent with the *2025 NPCC Québec Interim Review of Resource Adequacy*.[77] The planned outages for the summer period are reflected within this reliability assessment through the available capacity of resources. Hourly historical profiles are provided for wind generation.

3.3 Transfer Limits

Figure 2 depicts the system that was represented in this assessment, showing Area and assumed Base Case transfer limits for the summer 2026 period.

Transfer limits between and within some Areas are indicated in **Figure 2** with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the transmission representation for Ontario[78], New York[79], and New England[80] are provided in the respective references.

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76 See: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook.
77 See: 2025 Québec Interim Area Review of Resource Adequacy.pdf.
78 See: http://www.ieso.ca/localContent/ontarioenergymap/index.html.
79 See: 2026-27-IRM-Plan-Resolution-Approved.
80 The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/index.html.

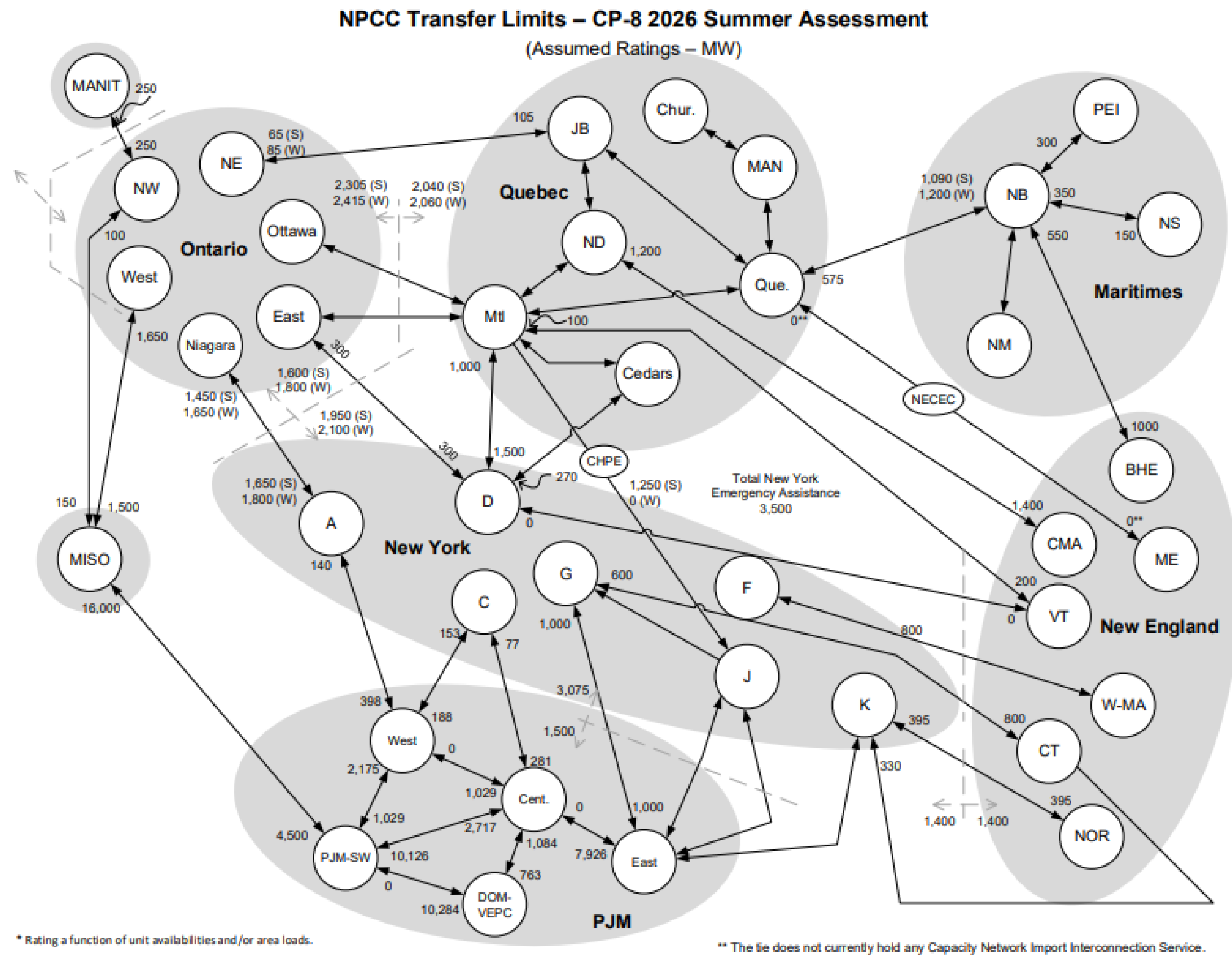

Figure 2: Assumed Transfer Limits[81]

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro-Québec can import up to 100 MW from New York.[82]

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-Des Cantons	Mtl	-Montréal	PEI	-Prince Edward Island
JB	-James Bay	C MA	-Central MA	CT	-Connecticut
MAN	-Manicouagan	W MA	-Western MA	NS	-Nova Scotia
NE	-Northeast (Ontario)	NBM	-Millbank	NW	-Northwest (Ontario)
MRO	-Midwest Reliability Organization	VT	-Vermont	CSC	-Cross Sound Cable
		Que	-Québec Centre	Cdrs	-Cedars
NM	-Northern Maine	CHPE	-Champlain Hudson Power Express	NECEC	-New England Clean Energy Connect

81 This diagram is not an exhaustive depiction of assumed transfer limits for the summer 2026 period. Further details, particularly regarding intra-Area transfers, can be found in the NPCC 2025 Long Range Adequacy Overview.
82 See: http://www.oasis.oati.com/HQT/.

Maritimes

Within the Maritimes Area, the areas of Nova Scotia, Prince Edward Island (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. The lines in northern New England generally are longer and fewer in number than those 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. 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 HVDC 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 (Phase II) and 1,200 MW of reverse export capability.

The New England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine was commercialized in early 2026. The NECEC energy-only contract into Maine/New England from Québec was not modeled for interconnection assistance in this probabilistic assessment. Only flow from Québec to New England is permitted on this tie line.

New York

The New York wholesale electricity market is divided into 11 pricing or load zones and is interconnected to Ontario, Québec, New England, and PJM. The transmission network is 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.

A project to increase transfer capability between Québec and New York by 1,250 MW of controllable HVDC connections is currently under construction and is expected to be placed in service this summer. It involves the construction of a ±400-kV DC underground transmission line about 60 km (37 miles) long from Hertel 735/315-kV substation just south of Montréal to the Canada – U.S.A. border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York State. From the international border crossing, the DC transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from DC to AC. The project in Québec also includes the construction of an AC to DC converter at Hertel substation. This line is associated with a 1,250 MW firm contract and is modeled in service for the duration of this study.

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. The Québec Area 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 (in New Brunswick), with New England at Highgate (in New England) and with New York at Châteauguay. The Radisson – Nicolet – Sandy Pond HVDC line ties 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 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 is now in service. Other ties between Québec and Ontario consist of radial generation and load that can be switched on either system.

A new 1,200 MW interconnection with New England, NECEC, was commissioned in January 2026, though its contracted exports and transmission capability were excluded from the probabilistic analysis. Additionally, the 1,250 MW CHPE project with New York, is expected to be commissioned in the summer of 2026 and will supply capacity to New York City during the summer months.

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 reduced operating reserves. **Table 7** summarizes the load relief assumptions modeled for each NPCC Area.

Actions	HQ	MT	NE	NY [83]	ON
1. Curtail Load Public Appeals RT-DR / SCR SCR Load / Man. Volt. Red.	- - - -	- - - -	- - - -	- - 0 0.22 %	- 1% - -
2. No 30-min Reserves	500	162	625	655	473
3. Voltage Reduction Interruptible Load [84]	250 -	- 327	252 -	1.43% 267	- 1,088
4. No 10-min Reserves Appeals / Curtailments	750 -	415 -	- -	- 74	945 -
5. 5% Voltage Reduction No 10-min Reserves Appeals / Curtailments	- - -	- - -	- 800 -	- 910 -	1.85% - -

Table 7: NPCC Operating Procedures – 2026 Summer Load Relief Assumptions (MW)

The Working Group recognizes that Areas may invoke these actions in any order, depending on conditions 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 analysis.

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 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 E** - Multi-Area Reliability Simulation Program Description - Resource Allocation Among Areas.

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. The assumptions are summarized in **Table 8**.

83 Values for New York's SCR Program has been derated to account for historical availability.
84 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.

Description	PJM	MISO
Peak Load (MW)	155,439	90,817
Peak Month	July	July
Assumed Capacity (MW)	184,872	102,915
Purchase/Sale (MW)	-1,633	978
Reserve (%)	23.0	20.7
Weighted Unit Availability (%)	89.5	83.7
Operating Reserves (MW)	3,655	3,906
Curtailable Load (MW)	7,955	5,728
No 30-min Reserves (MW)	1,218	2,670
Voltage Reduction (MW)	2,201	2,200
No 10-min Reserves (MW)	2,437	1,236
Appeals (MW)	400	400
Load Forecast Uncertainty (%)	100.0 +/- 5, 10, 15	100.0 +/- 3.7, 7.3, 11

Table 8: PJM and MISO Summer 2026 Base Case Assumptions[85]

85 Load and capacity assumptions for MISO based on NERC's Electricity and Supply Database (ES&D) available at: http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

Figure 3 shows the summer 2026 Projected Monthly 50/50 Peak Loads for NPCC, PJM and MISO for the 2021 Load Shape assumption.

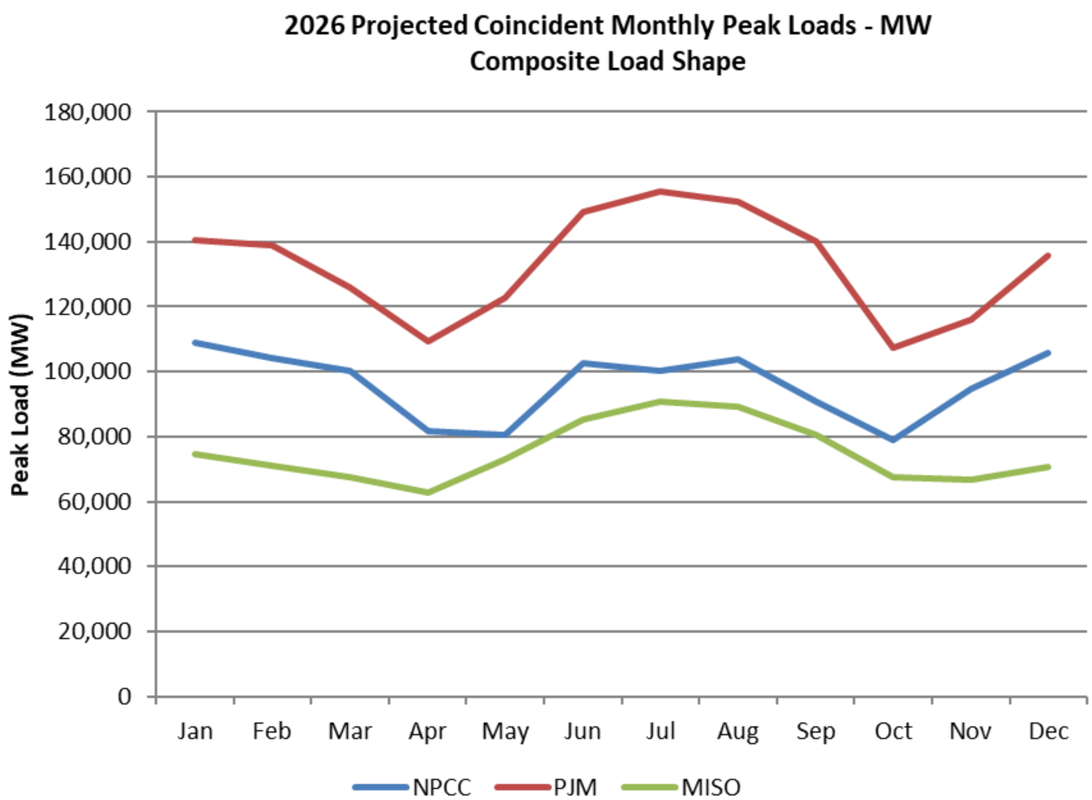

Figure 3: 2026 Projected Monthly Peak Loads – 2021 Load Shape

Beginning with the 2015 NPCC Long Range Adequacy Overview (LRAO),[86] 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 MISO 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.

3.6.1 PJM-RTO

The PJM model represents the As-Is System for the 2026 summer period and aligns with the forecast assumptions outlined in the 2025 NPCC Long Range Adequacy Overview.[87]

86 See: https://www.npcc.org/reliability-services?category=Resource%20Adequacy.
87 2025 NPCC Long Range Adequacy Overview.

Load Model

The load model used for the PJM-RTO in this study is consistent with the PJM Planning division's technical methods.[88] The hourly load shape is based on observed 2021 calendar year values, which reflects representative weather and economic conditions for a summer peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2026.[89] Load Forecast Uncertainty was modeled consistent with recent planning PJM models[90] considering seven load levels, each with an associated probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years the model is based on, sampling size, and how many years ahead in the future 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 as per results from the PJM's capacity market.

Expected Transmission Projects

The transfer values shown in the study are reflective of peak emergency conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at: www.pjm.com. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's regional Transmission Expansion Plan.[91]

88 Please refer to PJM Manuals 19 and 20 at https://www.pjm.com/-/media/documents/manuals/m19.ashx and https://www.pjm.com/%7E/media/documents/manuals/m20-redline.ashx for technical specifics.
89 See: 2026-load-report.pdf.
90 See: https://www.pjm.com/-/media/planning/res-adeq/2023-pjm-reserve-requirement-study.ashx.
91 See: https://www.pjm.com/planning.aspx.

3.7 Study Scenarios

The study evaluated three Cases; summary descriptions for the base and severe cases are provided in **Table 9** and **Table 10**, while the description for the sensitivity case is provided in **Table 11**.

	Base Case Assumptions	Severe Case – Additional Constraints
System	- As-Is System for the 2026 summer period - Transfers allowed between Areas - 2021 Load Shape[92] adjusted to the Area's year 2026 forecast (expected & higher load assumptions) - Solar and wind production based on best available hourly historically representative output data (2021-2025)	- Transfer capability between NPCC and the MISO - 'Other' reduced by 50%.
Maritimes	- The Capacity and Load[93] align with the forecast assumptions outlined in the 2025 NERC Long Term Reliability Assessment,[94] updated on most up to date system conditions available - ~1,844 MW of installed wind generation (modeled using probabilistically selected annual hourly 2017 wind shapes) - 122 MW external export contracts assumed - 321.5 MW of demand response (interruptible load) available	- Wind capacity is de-rated by half (~922 MW) during July and August due to calm weather - Natural Gas fueled units de-rated by half (~273.4) 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 (BTM PV forecast) for summer 2026 consistent with the 2026 ISO-NE Capacity, Energy, Loads, and Transmission (CELT) Report [95] - Active Demand for Capacity Resources and Imports based on 2026-2027 Capacity Commitment Period 2nd Annual Reconfiguration Auction (ARA2) held in 2025 - Behind the Meter Photovoltaic (BTM PV)[96] is modeled as a load modifier on an hourly	- Assume 50% reduction to the import capabilities of external ties - Maintenance overrun by 4 weeks

92 Current assumption based on previous year's load shape analysis (2025 Summer Load Shape Analysis).
93 Note: These 2026 Summer Reliability assessment assumptions were based on the 2025 NERC Long Term Reliability Assessment data for Summer 2026. Wind: NB: 374.2 MW, NS:1246.6 MW, PEI: 230.6 MW, NM: 42 MW.
94 2025 NERC Long Term Reliability Assessment Report.
95 See: 2026 CELT Reports (iso-ne.com).
96 Most of the solar resource development in New England consists of state-sponsored distributed resources, which do not participate in wholesale markets but reduce system load observed by ISO New England.

	Base Case Assumptions	Severe Case – Additional Constraints
	basis that corresponds to the NPCC load shape year	
New York	- Existing and planned generation resources and load forecast for the summer of 2026 consistent with the *2026 Gold Book*[59] - Assumptions consistent with *New York Installed Capacity Requirements for May 2026 through April 2027*[97] - Actual hourly plant profiles used for wind and solar generation over the period 2020-2024[98]	- Outages in southeastern New York (500 MW) - 50% reduction in effectiveness of SCR programs - 330 MW of reduced transfer capability into Long Island from PJM - 300 MW of reduced transfer capability into New York City from PJM.
Ontario	- Forecast consistent with Ontario IESO's Reliability Outlook – *An Adequacy Assessment of Ontario's Electricity System from April 2026 to September 2027*[99] - Firm Supply, demand, and transfers (imports and exports) as specified in the Reliability Outlook (RO) - Historical hourly profiles are used to model solar generation	- ~800 MW of maintenance extended into the summer period - ~800 MW of additional maintenance in September - Hydroelectric capacity and energy 10% lower than the Base Case
Québec	- Planned resources and load forecast consistent with the *2025 NPCC Québec Interim Review of Resource Adequacy*[45] for the summer 2026 period – including scheduled maintenance and hydro restrictions updated internally as of February 2026. - Hourly generation profiles used for wind - ~3,300 MW of sales to neighboring areas	- Additional 1,000 MW of capacity assumed to be unavailable for the summer peak period

Table 9: Base and Severe Case Assumptions for NPCC Areas

97 See: 2026-IRM-Study-Technical-Report.pdf. Assumptions consistent with the New York Installed Capacity Requirements for May 2026 to April 2027" it is important to know that the NYSRC Executive committee adopted the Special Sensitivity as the Final Base Case at the December 2025 meeting. This case adjusts resource assumptions by adding 512.9 MW in Zone J (specific Gowanus and Narrows units), adding 204.4 MW in Zone K (select GT and IC units), and removing 126.5 MW from Zone A (Cassadaga Wind).
98 Offshore wind uses normalized offshore wind shapes as published by NYISO over the period 2017-2022 and for land-based wind shape new units will use zonal hourly averaged or nearby units.
99 See: Reliability Outlook.

	Base Case Assumptions	Severe Case – Additional Constraints
PJM-RTO	- As-Is System for the 2026 summer period aligns with the forecast assumptions outlined in the *2025 NPCC Long Range Adequacy Overview* [45] - 2021 Load Shapes and Load Forecast Uncertainty adjusted to the 2026 forecast provided by PJM	- Load Forecast Uncertainty increased by one percent (1%) - Forced Outage rates increased for all units by one percent (1%) - No additional assumptions
MISO [100]	- As-Is System for the 2026 summer period - based on NERC ES&D database[101] - 2021 Load Shape and Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM	- No additional assumptions

Table 10: Base and Severe Case Assumptions for Neighboring Areas

	Sensitivity Case – Additional Constraints
System and NPCC Areas Besides New York	- Same as Base Case Assumptions, no additional assumptions
New York	- No wind/solar output in the Northern New York load pocket - Saranac Energy and Sithe-Massena peaker units assumed out-of-service - Zero imports on the Cedar interface with Québec
Neighboring Areas	- Same as Base Case Assumptions, no additional assumptions

Table 11: Sensitivity Case Assumptions for All Areas

100 Does not include the MISO-South (Entergy region).
101 See: Electricity Supply & Demand.

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 2026 period for the 50/50 peak load (probability-weighted average of the seven load levels simulated) for the Base Case. Detailed results from the MARS runs are provided in **Appendix B**, **Appendix C** and **Appendix D**.

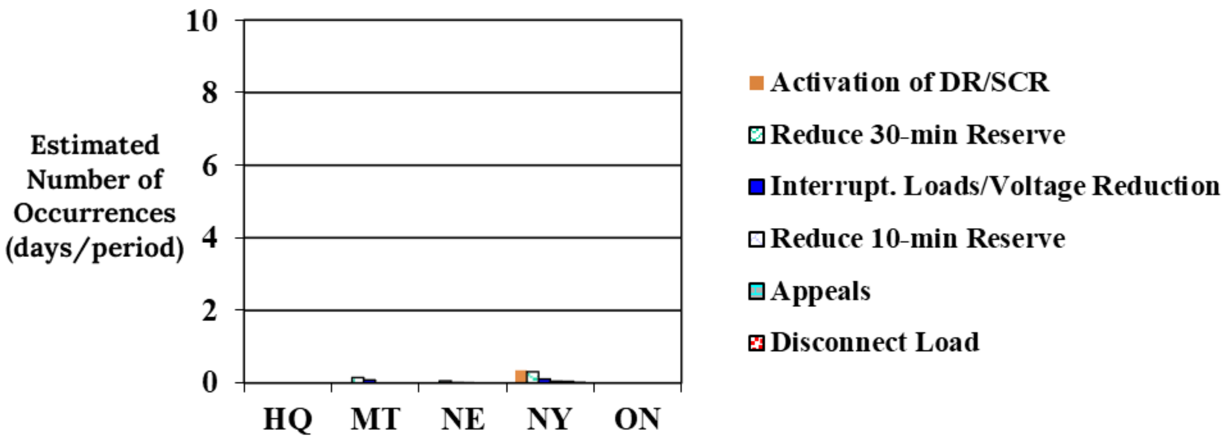

Figure 4: Estimated Use of Operating Procedure for Summer 2026
Base Case Assumptions – 50/50 Peak Load Level

Figure 5 shows the corresponding results for the higher peak load (based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring) for the Base Case.

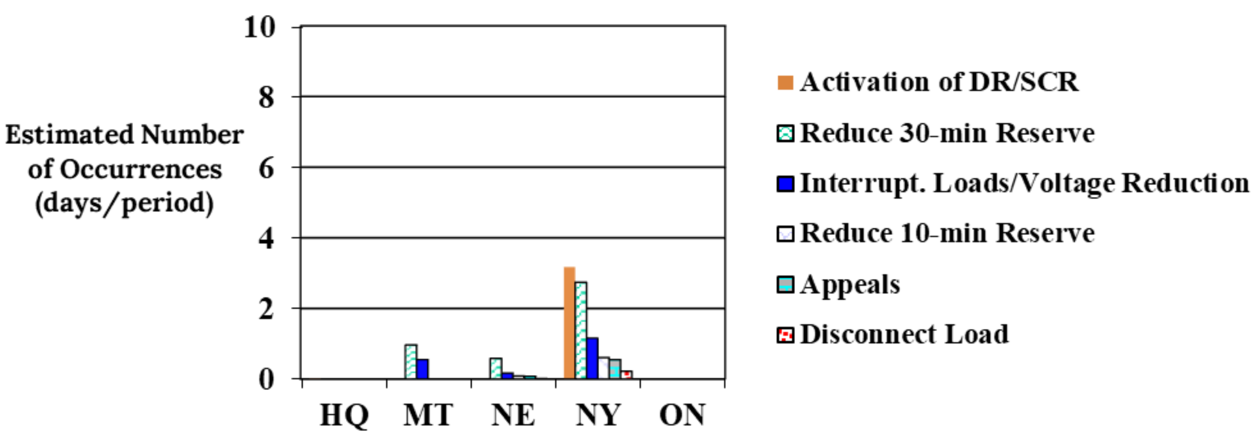

Figure 5: Estimated Use of Operating Procedures for Summer 2026
Base Case Assumptions – Higher Peak Load Levels

4.2 Severe Resource Case Scenario

Figure 6 shows the estimated use of operating procedures for the NPCC Areas for the 50/50 peak load (probability-weighted average of the seven load levels simulated) for the Severe Case. Detailed results from GE MARS runs are provided in **Appendix B**, **Appendix C** and **Appendix D**.

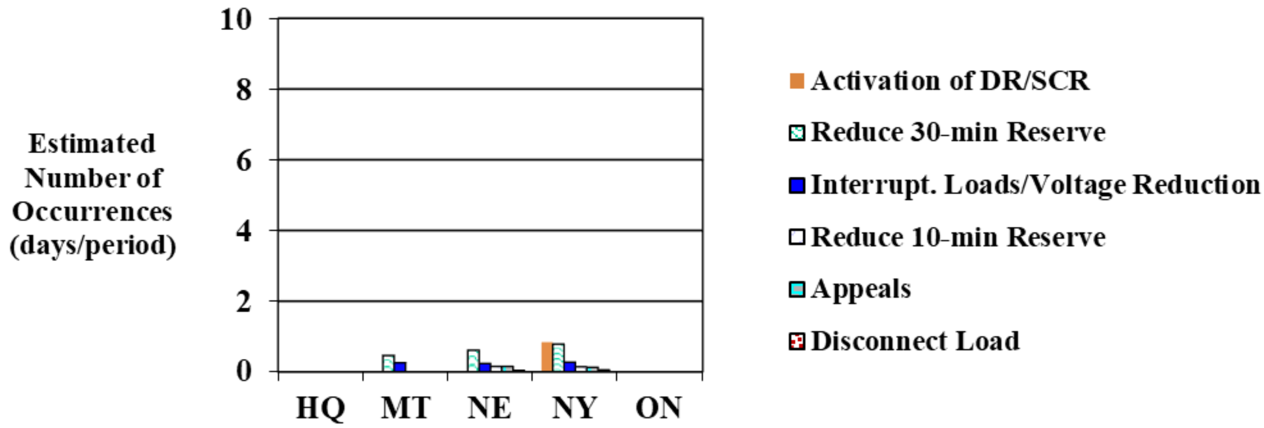

Figure 6: Estimated Use of Operating Procedure for Summer 2026
Severe Case Assumptions – 50/50 Peak Load Level

Figure 7 shows the estimated use of the indicated operating procedures for the Severe Case for the higher peak load level (based exclusively on only the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring).

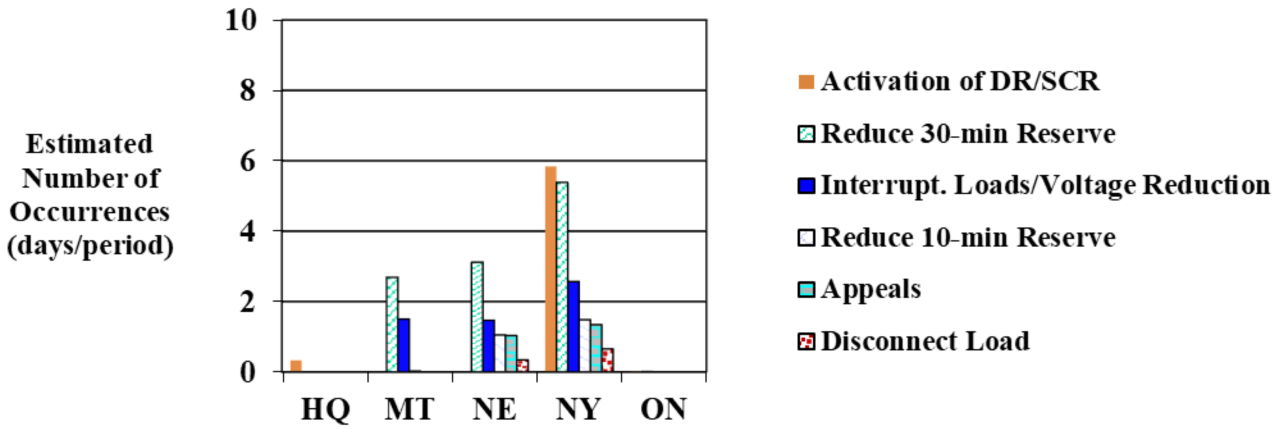

Figure 7: Estimated Use of Operating Procedure for Summer 2026
Severe Case Assumptions – Higher Peak Load Level

5. Historical Review

Table 12 compares NPCC Area's actual 2025 summer peak demands against the previous forecast assumptions based on the 2025 Summer Assessment.

Area	Date	Actual (MW)	Forecast (MW)		Forecast
			50/50 Peak[102]	Higher Peak[103]	Month
Maritimes	08/11/2025	3,528	3,695	4,035	May
New England	06/24/2025	26,024[104]	24,803[105]	27,314	July
New York	06/24/2025	31,857	31,650	34,176	July
Ontario	06/24/2025	24,862	23,475	26,871	July
Québec	08/11/2025	22,962[106]	23,285	26,037	August

Table 12: Comparison of NPCC 2025 Actual and Forecast Summer Peak Loads

A summary review of the last summer's demand and main operational issues are presented in the CO-12 Working Group's study, "*NPCC Reliability Assessment for Summer 2025*", May 2026,[107] **Section** 7, while a detailed historical weather review is presented in **Appendix G**.

A summary review of last summer's use of operating procedures is shown below in **Table 13**. While a prescribed order of these operating procedures was used in this assessment, Areas may invoke these actions in any order, depending on conditions at the time. The forecast range of values comes from **Appendix VIII** of the *NPCC Summer 2025 Reliability Assessment*,[108] capturing both the base and severe case scenario assumptions.

102 The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.
103 The higher peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.
104 This is the ISO-NE planning version of the peak load that includes load served by Settlement Only Generators (SOGs) and may be slightly different than the peak loads reported by operations that do not include SOGs. https://www.iso-ne.com/static-assets/documents/100008/2024_energy_peak_by_source.xlsx The data represent, in megawatt-hours (MWh), the amount of electricity assigned to each fuel type during the week. The data provided are for the full system, including "settlement only" generators that do not actively offer their output into the wholesale markets.
105 New England's peak value is based on the 2025 CELT on May 6, 2025, under this link: https://www.iso-ne.com/celt.
106 Represents the all-time Québec Summer Peak Demand.
107 See: Seasonal Assessment.
108 See: *NPCC Multi-Area Probabilistic Reliability Assessment for Summer 2025*.

Area	Activation of DR/SCR		Reduce 30-min Reserve		Interruptible Loads/Voltage Reduction		Reduce 10-min Reserves		Appeals		Disconnect Firm Load	
	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
Maritimes	-	-	0	6.2 – 44	0	3.1 – 28	0	0.1 – 2.0	0	0.0 – 0.1	0	0.0 – 0.1
New England[109]	-	-	1	0.2 – 12	0	0.1 – 8.7	0	0.1 – 7.5	0	0.1 – 7.4	0	0.0 – 4.4
New York[110]	9	0.2 – 8.7	1	0.2 – 8.8	0	0.1 – 5.4	0	0.0 – 4.3	0	0.0 – 3.9	0	0.0 – 2.1
Ontario[111]	1	0.0 – 9.1	0	0.0 – 3.3	1	0.0 – 1.6	0	0.0 – 0.5	0	0.0 – 0.2	0	0.0 – 0.1
Québec	-	-	0	0.0 – 0.0	-	-	0	0.0 – 0.0	-	-	0	0.0 – 0.0

Table 13: Comparison of NPCC 2025 Actual and Forecast[112] Use of Operating Procedures (Event-Days)

109 See: NEPOOL Report on Implementation of ISO-NE OP-4 on June 24, 2025.
110 See: NYISO Summer 2025 Hot Weather Operations.
111 See: 2025 Year in Review.
112 Forecasted range of operating procedure usage are for the Base Case scenario expected peak load level and the Severe Case scenario higher peak load levels as reported in the *NPCC Multi-Area Probabilistic Reliability Assessment for Summer 2025*.

6. Conclusions

This probabilistic assessment modeled the NPCC Region across a range of four scenarios. These scenarios include a Base Case scenario, conducted at both a 50/50 peak load level (50% chance of occurrence) and a higher peak load level (approximately 7% chance of occurrence), as well as a Severe Case scenario conducted at the same two peak load levels. The Severe Case scenario contains additional assumptions with Area specific low likelihood reduced resource conditions.

For each scenario, expected reliance on non-firm imports (external assistance) and expected operating procedure usage is estimated to meet demand. While a prescribed order of these operating procedures was used in this assessment, Areas may invoke these actions in any order, depending on conditions at the time. In this assessment, expected occurrences of less than 0.5 days per period are not considered significant.

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case scenario and 50/50 peak load forecast, no NPCC areas are expected to implement their operating procedures during the summer of 2026. The Maritimes, New England, and New York show a likelihood of relying on non-firm imports to meet peak demands.

Higher Peak Load Levels

Under higher peak load levels, the Maritimes, New England, and New York show a likelihood of activating their operating procedures in addition to relying on non-firm imports to meet peak demands. For all three Areas, this expected operating procedure usage includes a reduction of 30-minute reserves. Additionally, the Maritimes and New York show a likelihood of initiating interruptible loads. New York also exhibits an expected likelihood of implementing voltage reduction, reducing 10-minute reserves, and initiating public appeals to meet these elevated peak load demands.

Severe Case Scenario Summary

50/50 Peak Load Level

Under the Severe Case scenario and 50/50 peak load forecast, only New England and New York are expected to rely on their operating procedures, though the Maritimes shows a likelihood of relying on non-firm imports to meet peak demands. New England and New York demonstrate a likelihood of reducing 30-minute reserves and activating demand response resources.

Higher Peak Load Levels

The Severe Case scenario and higher peak load levels represents the most conservative scenario modeled in this probabilistic assessment, combining reduced resource conditions with higher-than-expected demand. Under this scenario, the results of this analysis indicate a risk of Loss of Load Expectation (LOLE) during the summer months for New York and New England. Strategies and procedures are in place to manage potential operational challenges and emergencies as they arise.

All five NPCC Areas show a likelihood of relying on external assistance at various times during these assumed conditions. While it is feasible for widespread weather patterns to cause higher-than-expected demand across the entire NPCC footprint, it is unlikely that the reduced resource condition assumptions associated with the Severe Case scenario will affect all five NPCC Areas simultaneously.

Québec

The Québec Area is not expected to require use of their operating procedures designed to mitigate resource shortages during the Summer of 2026. The Québec Area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of cumulative LOLE,[113] Loss of Load Hours (LOLH),[114] or Expected Unserved Energy (EUE)[115] risks over the summer May – September period for all the scenarios modeled.

LOLH and EUE can provide insight on system reliability because of their ability to measure loss of load duration and magnitude. EUE is helpful in quantifying the reliability risk impacts of weather or other natural events.

Ontario

The Ontario Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May – September period for all the scenarios modeled. Only the severe case scenario with reduced resources, higher peak load level conditions resulted in a significant amount of reliance on external assistance.

New England

Under the Severe Case scenario and for the higher peak load levels, assuming low likelihood of reduced resource conditions (considering the impact of scheduled maintenance extended

113 LOLE: The expected number of days which contain an event in which system load is not served in a given time period.
114 LOLH: The expected number of hours which contain an event in which system load is not served in a given time period.
115 EUE: The expected amount of energy (MWh) that will not be served in a given time period.

into the summer period and a 50% reduction in the import capabilities of external ties) the results indicated a negligible estimated cumulative LOLE risk (0.34 event-days/period), with associated LOLH (1.18 event-hours/period) and EUE (628 MWH/period) with the highest risk occurring in June and July, with some in August.

New York

Under the Severe Case scenario and for the higher peak load levels, assuming low likelihood of reduced resource conditions (assuming approximately 500 MW of extended maintenance in southeastern New York, a 630 MW reduction in cable transmission across HVDC facilities, and a 50% decrease in the effectiveness of demand response programs) the results indicated an estimated cumulative LOLE risk (0.66 event-days/period), with associated LOLH (2.00 event-hours/period) and EUE (1,255 MWh/period) with the highest risk occurring in August, with some risk occurring in June and July. Negligible cumulative LOLE risks were estimated over the summer May to September period for all other scenarios modeled.

Maritimes

The Maritimes Area is winter peaking and did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the summer May – September period for all the scenarios modeled. However, the results did show a reliance on external assistance in all four scenarios, with a minimum of 11.8 event-days/period in the base case expected load level conditions. Only the higher peak load scenarios demonstrate a notable use of operating procedures, including reducing 30-minute reserves and initiating interruptible loads.

Appendix A: Objective, Scope of Work and Schedule[116]

Objective

On a consistent basis, evaluate the near-term seasonal resource adequacy of NPCC Areas, reflecting the NPCC Area and proposed neighboring region's plans as an input to the assessment to meet their respective resource adequacy planning criteria. The potential effects of proposed market mechanisms in NPCC and neighboring regions that are anticipated to provide for future adequacy will be included in the evaluation.

In meeting this objective, the CP-8 Working Group (WG) 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 2026-2027 period, consistent with the corresponding reliability assessment assumptions of the NPCC CO-12 WG.

Scope

The near-term seasonal analyses will update the WG's G.E. MARS database to develop a model suitable for the 2026 - 2027 period to estimate the resource adequacy of NPCC Areas, with consideration for neighboring Regions. The analysis will consider Base Case (i.e., likely available resources and transmission) as well as Area-identified Severe and Sensitivity Case[117] assumptions for the May to September 2026 summer, and November 2026 to March 2027 winter seasonal periods, recognizing:

- Uncertainty in forecasted demand.
- Scheduled outages of transmission.
- Forced and scheduled outages of generation facilities, including fuel supply disruptions.
- Impacts of Sub-Area transmission constraints.
- Impacts of proposed load response programs.
- Historical hourly load shape analysis (considering the impact of DER and PV forecasts).
- Reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data, as appropriate.

Reliability for the near-term seasonal analyses (2026 - 2027) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages, including

116 TFCP Approved – February 4, 2026.
117 Assumptions subject to further review by the CP-8 WG/TFCP.

expected reliability metrics and analysis supporting related NERC Reliability Assessment Subcommittee probabilistic analysis requirements.

Schedule

A report combining the results of the CP-8 Working Group 2026 NPCC Summer Probabilistic Multi-Area Reliability Assessment, and the corresponding CO-12 Working Group 2026 Summer Reliability Assessment will be developed and approved by the NPCC Task Forces on Coordination of Operations and Planning no later than by May 15, 2026.

Appendix B: Detailed Study Results (event-days/month)

Base Case	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal /Disc	30-min	IL	10-min	Appeal/Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal/Disc
2021 Load Shape - 50/50 Load																						
May	-	-	-	-	0.002	-	--	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.068	0.042	-	-	0.016	0.003	0.002	0.002	0.000	0.058	0.023	0.008	0.007	0.003	-	-	-	-
Jul	-	-	-	-	0.070	0.034	0.002	-	0.026	0.008	0.004	0.003	0.001	0.096	0.027	0.013	0.010	0.004	-	-	-	-
Aug	-	-	-	-	0.317	0.180	0.001	-	0.016	0.003	0.001	0.001	0.000	0.156	0.058	0.030	0.026	0.010	-	-	-	-
Sep	-	-	-	-	0.004	0.002	-	-	-	-	-	-	-	0.000	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.462	0.258	0.003	-	0.057	0.013	0.007	0.006	0.001	0.309	0.108	0.050	0.043	0.017	-	-	-	-
2021 Load Shape – Higher Peak Load Levels																						
May	-	-	-	-	0.022	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.398	0.242	0.005	-	0.144	0.037	0.021	0.021	0.003	0.406	0.197	0.088	0.082	0.026	-	-	-	-
Jul	-	-	-	-	0.088	0.040	0.001	-	0.279	0.099	0.049	0.041	0.011	0.918	0.274	0.136	0.115	0.056	-	-	-	-
Aug	-	-	-	-	0.416	0.248	0.000	-	0.160	0.034	0.017	0.016	0.002	1.412	0.687	0.383	0.351	0.141	-	-	-	-
Sep	-	-	-	-	0.041	0.017	-	-	-	-	-	-	-	0.001	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.964	0.551	0.007	-	0.583	0.169	0.086	0.078	0.016	2.738	1.159	0.606	0.548	0.223	-	-	-	-

Table 14: Base Case Assumptions - Expected Need for Indicated Operating Procedures (event-days/period)

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.

Severe Case Results	Québec					Maritimes					New England					New York					Ontario			
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl/Disc
2021 Load Shape - 50/50 Load																								
May	-	-	-	-	-	0.002	0.000	-	-	-	0.001	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	0.068	0.042	0.001	-	-	0.222	0.080	0.053	0.053	0.012	0.172	0.066	0.030	0.025	0.009	-	-	-	-
Jul	-	-	-	-	-	0.070	0.034	0.002	-	-	0.155	0.082	0.054	0.053	0.016	0.228	0.066	0.032	0.026	0.001	-	-	-	-
Aug	-	-	-	-	-	0.317	0.180	0.001	-	-	0.232	0.073	0.047	0.047	0.011	0.384	0.141	0.083	0.073	0.035	-	-	-	-
Sep	-	-	-	-	-	0.004	0.002	-	-	-	--	--	--	--	--	0.001	0.000	0.000	0.000	-	-	-	-	-
May-Sep	-	-	-	-	-	0.462	0.258	0.003	-	-	0.610	0.235	0.154	0.153	0.039	0.785	0.273	0.145	0.124	0.055	-	-	-	-
2021 Load Shape – Highest Load Levels																								
May	-	-	-	-	-	0.022	0.004	-	-	-	0.010	0.002	0.002	0.002	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	0.401	0.242	0.005	-	-	1.096	0.522	0.391	0.388	0.115	0.997	0.507	0.270	0.241	0.106	0.005	0.002	0.002	-
Jul	-	-	-	-	-	0.400	0.180	0.006	0.001	0.001	0.655	0.397	0.291	0.280	0.125	1.590	0.616	0.305	0.025	0.117	-	-	-	-
Aug	0.001	-	-	-	-	1.823	1.059	0.012	-	-	1.359	0.547	0.370	0.364	0.103	2.793	1.445	0.910	0.846	0.432	0.004	-	-	-
Sep	-	-	-	-	-	0.041	0.017	-	-	-	-	-	-	-	-	0.006	0.000	0.000	0.000	-	-	-	-	-
May-Sep	0.002	-	-	-	-	2.687	1.502	0.023	0.001	0.001	3.119	1.468	1.053	1.034	0.343	5.386	2.569	1.485	1.341	0.065	0.009	0.002	0.002	-

Table 15: Severe Case Scenario - Expected Need for Indicated Operating Procedures (event-days/period)

Notes: 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: Detailed Study Results (event-hours/month)

Base Case																						
	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal/Disc	30-min	IL	10-min	Appeal/Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal/Disc
2021 Load Shape - 50/50 Load																						
May	-	-	-	-	-	0.005	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	0.436	0.194	0.001	0.046	0.008	0.004	0.004	0.000	0.167	0.063	0.024	0.021	0.007	-	-	-	-
Jul	-	-	-	-	-	0.092	0.037	0.001	0.081	0.024	0.010	0.009	0.002	0.312	0.084	0.039	0.030	0.012	-	-	-	-
Aug	-	-	-	-	-	0.297	0.100	0.000	0.042	0.007	0.003	0.003	0.000	0.452	0.149	0.073	0.065	0.023	-	-	-	-
Sep	-	-	-	-	-	0.020	0.007	-	-	-	-	-	-	0.000	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	-	0.850	0.339	0.002	0.169	0.039	0.017	0.015	0.003	0.931	0.295	0.135	0.117	0.042	-	-	-	-
2021 Load Shape – Higher Peak Load Levels																						
May	-	-	-	-	-	0.066	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	2.644	1.176	0.013	0.497	0.111	0.058	0.058	0.007	1.535	0.679	0.285	0.259	0.076	-	-	-	-
Jul	-	-	-	-	-	0.473	0.213	0.004	0.960	0.327	0.145	0.124	0.029	3.289	0.984	0.461	0.392	0.160	-	-	-	-
Aug	-	-	-	-	-	2.464	1.004	0.001	0.459	0.088	0.037	0.035	0.005	4.720	1.977	1.009	0.927	0.335	-	-	-	-
Sep	-	-	-	-	-	0.193	0.074	-	-	-	-	-	-	0.003	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	-	5.841	2.474	0.017	1.916	0.526	0.241	0.217	0.040	9.546	3.640	1.754	1.578	0.572	-	-	-	-

Table 16: Base Case Assumptions - Expected Need for Indicated Operating Procedures (event-hours/month)

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.

Severe Case Results	Québec					Maritimes					New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
2021 Load Shape - 50/50 Load																									
May	-	-	-	-	-	0.005	0.001	-	-	-	0.001	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-
Jun	0.000	-	-	-	-	0.436	0.194	0.001	-	-	0.817	0.285	0.188	0.187	0.042	0.521	0.195	0.087	0.075	0.027	0.002	0.002	0.001	-	-
Jul	-	-	-	-	-	0.466	0.193	0.007	0.000	0.000	0.584	0.281	0.189	0.186	0.052	0.755	0.206	0.099	0.081	0.034	0.000	-	-	-	-
Aug	0.000	-	-	-	-	2.047	0.850	0.003	-	-	0.733	0.218	0.142	0.140	0.028	1.300	0.414	0.244	0.215	0.098	0.000	-	-	-	-
Sep	-	-	-	-	-	0.021	0.007	-	-	-	-	-	-	-	-	0.002	0.000	0.000	0.000	-	-	-	-	-	-
May-Sep	0.000	-	-	-	-	2.975	1.245	0.011	0.000	0.000	2.136	0.783	0.518	0.513	0.122	2.578	0.815	0.429	0.371	0.159	0.003	0.002	0.001	-	-
2021 Load Shape – Higher Peak Load Levels																									
May	-	-	-	-	-	0.066	0.008	-	-	-	0.020	0.004	0.003	0.003	-	-	-	-	-	-	-	-	-	-	-
Jun	0.001	-	-	-	-	2.650	1.176	0.013	-	-	4.444	1.970	1.412	1.409	0.417	3.963	1.900	0.931	0.832	0.324	0.031	0.027	0.022	-	-
Jul	-	-	-	-	-	2.589	0.952	0.028	0.005	0.005	2.798	1.635	1.160	1.125	0.465	6.166	2.186	1.026	0.877	0.376	0.001	-	-	-	-
Aug	0.002	-	-	-	-	12.851	5.794	0.036	-	-	4.879	1.773	1.196	1.185	0.295	11.085	4.918	2.976	2.771	1.296	0.007	-	-	-	-
Sep	-	-	-	-	-	0.196	0.072	-	-	-	-	-	-	-	-	0.019	0.001	0.000	0.000	-	-	-	-	-	-
May-Sep	0.003	-	-	-	-	18.351	8.002	0.076	0.005	0.005	12.141	5.382	3.771	3.722	1.178	21.233	9.004	4.933	4.480	1.996	0.039	0.027	0.022	-	-

Table 17: Severe Case Scenario - Expected Need for Indicated Operating Procedures (event-hours/month)

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.

Appendix D: Detailed Study Results (MWh/month)

Base Case	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal/Disc	30-min	IL	10-min	Appeal/Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal/Disc
2021 Load Shape - 50/50 Load																						
May	-	-	-	-	0.1	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	24.3	9.3	0.0	-	18.3	3.0	1.4	1.4	0.1	115.0	40.8	13.9	12.3	2.7	-	-	-	-
Jul	-	-	-	-	5.2	2.2	0.0	-	55.6	16.2	6.5	5.5	0.9	170.0	53.4	19.4	16.4	4.8	-	-	-	-
Aug	-	-	-	-	13.9	4.1	0.0	-	20.8	3.0	1.0	1.0	0.1	284.7	105.5	47.5	44.4	13.3	-	-	-	-
Sep	-	-	-	-	0.8	0.2	-	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	44.4	15.8	0.1	-	94.7	22.3	8.9	7.8	1.1	569.7	199.8	80.9	73.1	20.8	-	-	-	-
2021 Load Shape – Higher Peak Load Levels																						
May	-	-	-	-	1.6	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	154.0	61.8	0.4	-	233.2	45.1	20.7	20.6	1.8	1315.1	519.4	187.6	167.7	39.3	-	-	-	-
Jul	-	-	-	-	30.4	13.3	0.3	-	770.9	240.3	99.2	83.4	13.5	2150.0	745.7	278.1	239.2	70.6	-	-	-	-
Aug	-	-	-	-	132.2	44.2	0.0	-	270.0	43.4	15.4	14.4	1.7	3783.4	1517.5	703.4	662.9	202.9	-	-	-	-
Sep	-	-	-	-	9.0	2.8	-	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	327.1	122.3	0.6	-	1274.2	328.8	135.4	118.3	17.1	7248.8	2782.6	1169.0	1069.9	312.7	-	-	-	-

Table 18: Base Case Assumptions - Expected Need for Indicated Operating Procedures (MWh/month)

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.

Severe Case Results	Québec					Maritimes					New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
2021 Load Shape - 50/50 Load																									
May	-	-	-	-	-	0.1	0.0	-	-	-	0.5	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-
Jun	0.0	-	-	-	-	24.3	9.3	0.0	-	-	474.5	159.9	100.3	99.9	19.7	340.6	140.7	54.1	48.3	14.4	0.8	0.5	0.2	-	-
Jul	-	-	-	-	-	28.5	12.7	0.4	0.0	0.0	470.6	188.9	118.2	115.8	27.4	394.4	131.5	50.0	42.6	14.0	0.0	-	-	-	-
Aug	0.0	-	-	-	-	111.5	39.8	0.1	-	-	396.2	113.7	68.0	67.4	11.9	741.8	304.0	167.4	159.0	58.8	0.1	-	-	-	-
Sep	-	-	-	-	-	0.9	0.2	-	-	-	-	-	-	-	-	0.3	0.0	0.0	0.0	-	-	-	-	-	-
May-Sep	0.0	-	-	-	-	165.2	62.1	0.5	0.0	0.0	1341.8	462.7	286.5	283.1	59.0	1477.1	576.3	271.4	249.9	87.2	0.9	0.5	0.2	-	-
2021 Load Shape – Higher Peak Load Levels																									
May	-	-	-	-	-	1.6	0.2	-	-	-	7.5	1.7	1.0	1.0	-	-	-	-	-	-	-	-	-	-	-
Jun	0.0	-	-	-	-	154.6	61.8	0.4	-	-	3217.5	1310.1	881.2	877.7	209.4	3459.6	1650.0	699.5	635.4	195.9	12.3	8.0	3.2	-	-
Jul	-	-	-	-	-	143.3	59.1	2.3	0.1	0.1	3170.3	1498.1	972.5	937.1	287.3	4408.4	1665.2	654.9	571.0	184.7	0.5	-	-	-	-
Aug	0.1	-	-	-	-	803.6	318.2	0.8	-	-	3171.2	1043.1	655.7	649.2	131.0	8946.5	4170.3	2406.3	2320.2	874.4	1.8	-	-	-	-
Sep	-	-	-	-	-	9.1	2.9	-	-	-	-	-	-	-	-	2.7	0.0	0.0	0.0	-	-	-	-	-	-
May-Sep	0.1	-	-	-	-	1112.2	442.1	3.5	0.1	0.1	9566.5	3853.0	2510.4	2465.0	627.6	16817.3	7485.5	3760.7	3526.6	1255.0	14.6	8.0	3.2	-	-

Table 19: Severe Case Scenario - Expected Need for Indicated Operating Procedures (MWh/month)

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.

Appendix E: Multi-Area Reliability Program Description

General Electric's Multi-Area Reliability Simulation (MARS) program[118] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

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

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

Reliability Indices

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

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

The Working Group used both the daily LOLE and operating procedure indices for this analysis.

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

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

118 See: https://www.gevernova.com/consulting/planos/resource-adequacy.

expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

Resource Allocation Among Areas

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

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

Generation

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Hourly-based generation

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or as a unit with a specified capacity and available monthly energy (Type 2/3 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Hourly-based profile units are modeled as load modifiers. Charging and discharging of energy storage units is determined during the Monte Carlo solutions.

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:

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

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

Energy-Limited Units

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

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

A 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.

Type 3 (as-needed) energy limited units are dispatched on an as-needed bases during the Monte Carlo simulation and their generation profile usually changes from one replication to another. With this approach, the Type 3 energy-limited units are used only if the thermal capacity is not sufficient to serve the load. If there is sufficient thermal capacity in a given hour, the energy of the Type 3 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

Energy-storage units are modeled by providing their nameplate capacity and the amount of energy that they can store. GE MARS dispatches the stored energy when it can reduce negative margins in the system. When the system has a surplus of capacity, energy storage units are allowed to charge energy, as long as they do not cause loss-of-load events or use of emergency operating procedures.

Hourly-based Modifiers

Hourly-based modifiers (e.g., wind or solar) are modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week or a full 8,760 set of hourly values which is subtracted from the hourly loads for the unit's area.

Transmission System

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

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as an 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 F: Modeling Details

Details regarding the NPCC Area's assumptions for resources are described in the respective Area's most recent NPCC Area Review of Resource Adequacy.[119] In addition, the following Areas provided the following:

Existing Resources

Maritimes

Resources in the Maritimes Area are modeled with winter Dependable Maximum Net Capability (DMNC) ratings de-rated for the summer period.

New England

The New England generating unit ratings were consistent with their seasonal capability as reported in the 2026 CELT report.[120] Active Demand Capacity Resources and capacity imports are based on their Capacity Supply Obligations of the 2nd annual Reconfiguration Auction of Capacity Commitment Period of 2026-2027.

New York

The Base Case assumes that the Lower Hudson Valley, New York City, and Long Island localities will meet their locational installed capacity requirements as described in the New York ISO Technical Study Report Locational Installed Capacity Requirements Study covering the New York Control Area for the 2026-2027 Capability Year, dated January 16, 2026, and that New York State will meet the capacity requirements described in the New York Control Area Installed Capacity Requirements for the Period May 2026–April 2027, New York State Reliability Council, Technical Study Report, dated December 5, 2025.[75] NYSRC Executive committee adopted the Special Sensitivity as the Final Base, produced an IRM of 25.6% and "Minimum Locational Capacity Requirements" (MLCRs) of 79.8% and 107.5% for Load Zone J and Load Zone K, respectively for the period May 2026-April 2027.[121]

All in-service New York generation resources were modeled. The New York unit ratings were based on the DMNC values from the 2025 Load & Capacity Data of the NYISO (Gold Book).[59]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario Reliability Outlook - An adequacy

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119 See: NPCC Area Review of Resource Adequacy.
120 See: https://www.iso-ne.com/system-planning/system-plans-studies/celt.
121 See: 2026-2027 IRM Study: Database Alignment Report

assessment of Ontario's electricity system From April 2026 to September 2027 - March 19, 2026.[122]

Québec

The planned resources are consistent with the 2025 NPCC Québec Interim Review of Resource Adequacy.[123]

Resource Availability

Maritimes

Individual generating unit maintenance assumptions are based on approved maintenance schedules for the study period. Forced outage rates are based on the individual unit's historical data. If historical data is not available, forced outage rates are modeled based on generators of similar size and fuel type in the Area.

New England

This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period (2021-2025). 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 (NERC) average data for the same class of unit.

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2026–2027 Capability Year[74] and the New York Control Area Installed Capacity Requirement for the Period May 2026 to April 2027 New York State Reliability Council, December 5, 2025, report.[75]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario Reliability Outlook - An adequacy assessment of Ontario's electricity system From April 2026 to September 2027 - March 19, 2026.[124]

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122 See: Reliability Outlook (ieso.ca).
123 See: 2025 NPCC Québec Interim Review
124 See: Reliability Outlook (ieso.ca).

Québec

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

Thermal

Maritimes

Combustion turbine capacity for the Maritimes Area is winter Dependable Maximum Net Capability (DMNC). During summer, these values are de-rated accordingly.

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 historical 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 New York ISO 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.

Québec

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

Hydro

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.

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 historical median net real power output during Reliability Hours.

- The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.
- The Winter Intermittent Reliability Hours shall be hours ending 18:00 and 19:00 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

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 generators are classified as either run-of-river or peaking plants. Run-of-river facilities are aggregated on a zonal basis and represented using hourly production profiles that are randomly selected from up to 30 years of historical or simulated water-year data in each Monte Carlo iteration to capture hydrological variability. Peaking hydro plants are treated as dispatchable, energy-limited resources, with monthly limits on capacity and energy derived from the most recent five years of operating data, including minimum flow requirements and statistically defined maximum outputs.

Québec

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.

Solar

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.

New England

Solar resources are modelled using five years of hourly output profiles, based on simulated resource output during 2021-2025. With every sample draw, GE MARS chooses at random one of the five profiles to use for that sample.

Each hourly output profile is scaled to Network Resource Capability (NRC). Larger resources use unique profiles, representing their simulated output over 2021-2025, while smaller resources use shared, aggregate profiles, calculated by RSP zone.

New York

New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period (2020-2024) 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

Ontario provides 8,760 hours of hourly historical solar profiles for each year of each transmission-connected resource for the most recent five-year calendar period (2021 – 2025) based on production and foregone data.

Québec

The actual solar installed capacity is estimated at approximately 10 MW and does not affect the load monitored from the BPS perspective. For the summer period, solar power generation is derated by 100 percent.

Wind

Maritimes

The Maritimes Area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the five historical years (2020-2024) based on their simulated output. The wind in any particular hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area's actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. 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.

New England

Wind resources are modelled using five years of hourly output profiles, based on simulated resource output during 2021-2025. With every sample draw, MARS chooses at random one of the five profiles to use for that sample.

Each hourly output profile is scaled to Network Resource Capability (NRC). Larger resources use unique profiles, representing their simulated output over 2020-2024, while smaller resources use shared, aggregate profiles, calculated by RSP zone.

New York

New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period (2020-2024) 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.

Ontario

Ontario provides 8,760 hours of hourly historical wind profiles for each year of each transmission-connected resource for the most recent five-year calendar period (2021 – 2025) based on production and foregone data.

Québec

Wind generation is modeled using five years of hourly historical data (2021-2025), adjusted to meet the planned installed capacity.

Demand Response

Maritimes

Demand Response in the Maritimes Area is currently comprised of contracted interruptible loads.

New England

492 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. Curtailments are called by the New York ISO when reserve shortages are anticipated or during other emergency operating conditions.

SCRs are modeled as an operating procedure step activated to minimize the probability of customer load disconnection, subject to hourly response rates with a 1 call per day limit. SCR performance factors are captured in hourly response rates. 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, 898.1 MW of SCRs were modeled based on registrations. At the time of the summer peak, this amount was discounted to 724.1 MW based on historical availability.

Ontario

The demand measures assumed are up to 1,088MW for the summer period.

Québec

Around 1,000 MW of demand response is available during the summer period but are rarely used. DR programs are designed for the winter period.

Appendix G: Previous Summer Review

Weather

Highlights – (June-September 2025)[125]

The meteorological summer (June-August) average temperature for the contiguous U.S. was 73.3°F, 2.0°F above average, ranking 12th warmest on record. Temperatures were above average across much of the U.S., especially in the west and the northeast. 11 states had one of their 10 warmest summers on record.

The contiguous U.S. average maximum (daytime) temperature during June-August was 85.8°F, 1.4°F above average, ranking in the warmest third of the historical record. Daytime temperatures were above average across much of the eastern and western contiguous U.S., with near-record temperatures in the Southwest. Near- to below-average temperatures were observed across the northern Great Plains down to the Gulf Coast. Arizona, California, and Utah ranked warmest on record, with 13 additional states experiencing a top 10 warmest June-August for daytime temperatures.

The contiguous U.S. average minimum (night-time) temperature during this three-month period was 61.1°F, 2.7°F above the 20th century average, ranking 3rd warmest in the historical record. Above-average nighttime temperatures were also observed across much of the U.S.

Based on the Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during June-August was 185 percent of average and was the 11th-highest value on record.

The contiguous U.S. summer precipitation total was 8.69 inches, ranking in the middle third of the June-August record. Precipitation was above average across portions of the Plains and upper Mississippi Valley, and much below average across the Northeast. Vermont recorded its driest summer since 1913, and New Hampshire recorded its driest summer on record during the June–August period.

The U.S. Climate Extremes Index (USCEI) for the summer period was 26 percent above average, ranking in the upper third of the period of record.

On the regional scale, all regions experienced above average warm nighttime temperatures, with the Northwest, West, Southwest, Ohio Valley, and Southeast regions all experiencing elevated CEI composite values.

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125 NOAA National Centers for Environmental Information, Monthly National Climate Report for August 2025, published online September 2025, retrieved on March 17, 2026 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202508.

Northeast Region

June[126]

June was exceptionally hot, with a widespread heatwave affecting the Central and Eastern U.S. regions and included multiple significant flash flood events in the Northeast.

The Northeast's average temperature for June was 67.5 degrees F, 2.0 degrees F above normal. All twelve Northeast states wrapped up June above normal, with average temperatures ranging from 1.0 degrees F above normal in Maine, to 2.5 degrees F above normal in West Virginia. June ranked among the 14 hottest Junes on record for 11 of 12 states: Delaware, fifth hottest; Maryland, sixth hottest; Rhode Island and West Virginia, seventh hottest; New York, ninth hottest; Pennsylvania, 10th hottest; Connecticut and Massachusetts, 11th hottest; New Jersey and Vermont, 12th hottest; and New Hampshire, 14th hottest. June 2025 was the hottest June on record in Islip, New York.

The Northeast averaged 4.00 inches of precipitation, which was 91 percent of normal. For the 12 Northeast states, precipitation ranged from 38 percent of normal in Rhode Island to 110 percent of normal in Pennsylvania, with 10 states being drier than normal. Delaware experienced its 12th driest on record, and Delaware its 17th driest, while Rochester, New York saw its wettest June day since its records began in 1871 with 3.15 inches of rain on June 18.

The U.S. Drought Monitor from June 3 showed 1 percent of the Northeast in drought and 6 percent as abnormally dry. Mostly normal precipitation slightly reduced drought levels throughout the month. The U.S. Drought Monitor from June 24 showed 1 percent of the Northeast in drought, 3 percent as abnormally dry.

The Northeast experienced severe weather and flash flooding multiple times throughout June, including an extended period from June 5 to 10. On June 5, a 3-inch hailstone fell in Steuben County, New York, among some of the largest hailstones to have been reported in the state. The severe weather was accompanied by tornados throughout the month. On June 22, central New York experienced two EF-1 tornados, which resulted in 3 deaths.

July[127]

July was full of record-hot temperatures and multiple flash floods and severe weather events.

The Northeast had its fourth warmest July since records began in 1895 with an average temperature of 72.1 degrees F, 2.9 degrees F above normal. State average temperature departures for July ranged from 2.0 degrees F above normal in Maine to 3.8 degrees F above

126 NOAA National Centers for Environmental Information, Monthly National Climate Report for June 2025, published online July 2025, retrieved on March 17, 2026 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202506.
127 NOAA National Centers for Environmental Information, Monthly National Climate Report for July 2025, published online August 2025, retrieved on March 20, 2026 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202507.

normal in West Virginia. This July ranked as the warmest on record for West Virginia and among the 13 warmest Julys for 11 additional states: Maryland, second warmest; Connecticut, third warmest; Delaware, New York, and Pennsylvania, fourth warmest; New Jersey, sixth warmest; Rhode Island and Vermont, seventh warmest; New Hampshire, eighth warmest; Massachusetts, ninth warmest; and Maine, 13th warmest.

The Northeast picked up 3.72 inches of precipitation, 86 percent of normal. July precipitation for the 12 Northeast states ranged from 50 percent normal in New Hampshire to 175 percent normal in Delaware. This equated to the seventh driest July for New Hampshire and the 10th wettest for Delaware.

The U.S. Drought Monitor from July 1 showed one percent of the Northeast in drought and three percent as abnormally dry. Patches of abnormal dryness were present in areas closer to the coast from southern Maryland to Southern Maine, and pockets of moderate drought existed in central Maryland and southeastern Massachusetts. The U.S. Drought Monitor from July 29 showed less than one percent of the Northeast in drought, and four percent as abnormally dry. Mandatory water restrictions were enacted in parts of Massachusetts, though agriculture impacts were generally limited.

On July 3, a supercell traveled from central New York into northeastern Pennsylvania, with widespread winds of up to 70 mph, and more localized winds of up to 100 mph. On July 7, Ontario County, New York experienced an EF-2 tornado, and Tropical Depression Chantal brought rain and localized flash flooding to the southeastern corner of the northeast region.

Throughout the middle of July, storms brought localized flash flooding to a variety of areas, including Vermont, New York City, and Maryland, all resulting in water rescues. On July 31, the region experienced an extreme rainfall and flash flooding event from Washington, D.C. to New York City. Ocean County, New Jersey recorded 4.78 inches of rain in two hours, which is a 200-year storm event.

Other items of note included smoke from wildfires burning in the western U.S. and Canada causing hazy skies in the region several times in July and multiple instances of algal blooms and/or increased bacteria causing beaches continued to cause issues throughout the month

August[128]

While August temperatures were relatively cool, the northeast region experienced a very dry month.

The Northeast's average temperature for August was 67.3 degrees F, 1.3 degrees F cooler than normal, and the coolest August since 2017. For the 12 Northeast states, average temperatures for August ranged from 3.4 degrees F below normal in Delaware to exactly normal in Maine.

128 NOAA National Centers for Environmental Information, Monthly National Climate Report for August 2025, published online September 2025, retrieved on March 20, 2026 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202508.

The region's average summer temperature was 69.3 degrees F, 1.2 degrees F warmer than normal. State average temperatures for summer ranged from 0.3 degrees F above normal in Delaware to 1.8 degrees F above normal in West Virginia. Summer 2025 ranked among the 20 hottest for all 12 Northeast states.

The Northeast had its second driest August since 1895, picking up 1.92 inches of precipitation, 48 percent of normal, just behind the driest August which was 1.80 inches in 1957. State precipitation totals for August ranged from 33 percent normal in New Hampshire and Vermont to 66 percent normal in Connecticut and Rhode Island. This August was the driest on record for Vermont and among the 20 driest Augusts for nine additional states: New Hampshire and West Virginia, second driest; Pennsylvania, fourth driest; Maryland, seventh driest; New York, eighth driest; Maine, ninth driest; New Jersey, 13^{th} driest; Delaware 15^{th} driest; and Massachusetts, 20th driest. The Northeast ended the summer with 9.94 inches of precipitation, 78 percent of normal, and 19^{th} driest summer on record. Summer precipitation for the 12 Northeast states ranged from 57 percent normal in New Hampshire to 92 percent normal in West Virginia. This summer was the driest on record for New Hampshire, second driest for Vermont, sixth driest for Maine, and 17^{th} driest for New Hampshire.

The U.S. Drought Monitor from August 5 showed less than one percent of the Northeast in drought, and 17 percent as abnormally dry. Abnormal dryness was found in eight of the 12 states. Little rainfall combined with above average temperatures led to the rapid expansion and intensification of drought and abnormal dryness throughout the month. The U.S. Drought Monitor from August 26 showed 20 percent of the Northeast in drought and 38 percent as abnormally dry. During August, record low streamflow was present at times in multiple locations including coastal Maine, southern New Hampshire, northern Vermont, southeastern Massachusetts, western New York, and southern New Jersey. Also reported were dry wells, lower-than-average water levels, stressed crops, burn bans, and elevated fire risk in several states.

Other items of note included smoke from wildfires burning in the western U.S. and Canada causing hazy skies and reduced air quality in northern parts of the region in early-August, and major temperature swings in Northern Maine during mid-August. Hurricane Erin produced rough surf and rip currents along the East Coast in mid-August, and several instances of algal blooms and/or increased bacteria causing beaches, lakes, and other waterways to close for recreational activities during the month.

September[129]

September was warm and dry overall for the Northeast, allowing drought conditions to intensify.

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129 NOAA National Centers for Environmental Information, Monthly National Climate Report for September 2025, published online October 2025, retrieved on March 20, 2026 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202509.

The Northeast had an average temperature of 62.9 degrees F in September, which was 1.3 degrees F above normal. Average temperatures for September in the 12 Northeast states ranged from exactly normal in Rhode Island to 1.9 degrees F above normal in New Hampshire, with 11 of the states on the warm side of normal. This September ranked among the 20 warmest Septembers on record for five states: Maine and New Hampshire, 12th warmest; Pennsylvania and Vermont, 19th warmest; and New Jersey, 20th warmest.

The Northeast received 2.71 inches of precipitation during September, which was 67 percent normal. September precipitation for the 12 Northeast states ranged from 56 percent normal in Pennsylvania to 105 percent normal in Rhode Island, the only wetter-than-normal state.

The U.S. Drought Monitor from September 2 showed 30 percent of the Northeast in drought and 41 percent as abnormally dry. Abnormal dryness was found in 11 of the 12 Northeast states, with all of Vermont in drought for the first time since the U.S. Drought Monitor began in 2000. Dry weather during September, along with other factors like reduced soil moisture, and declining streamflow and groundwater levels, led to intensification and expansion of drought and abnormal dryness across the region. The U.S. Drought Monitor from September 30 showed 49 percent of the Northeast in drought and 43 percent as abnormally dry. By the end of the month, moderate drought was found in every state but Delaware, with abnormal dryness covering most of the areas that were not in drought.

Throughout September, small, severe weather events brought several tornados to the region. On September 24, an EF-0 tornado in southeastern New York left damaged trees along its nearly 16-mile-long path. In the second half of September, three hurricanes-Gabrielle, Humberto, and Imelda-produced rough surf and rip currents along the Eastern Seaboard.

Appendix H: Detailed Sensitivity Case Study Results (event-days/month)

Champlain Hudson Power Express In-Service Delay

The NPCC 2026 Summer Probabilistic Risk Assessment included a sensitivity analysis to evaluate the reliability impact of a potential delay in the commercial operation of the Champlain Hudson Power Express (CHPE), a 1,250-MW HVDC merchant transmission line originally scheduled to begin operations on May 1. This sensitivity analysis was performed to ensure the NPCC assessment accounts for the interdependence between major transmission project timelines and the retirement schedules of local peaking resources required to maintain system stability.

In this scenario, CHPE is assumed to be unavailable for the duration of the 2026 summer operating period. While the base case assumes CHPE is fully operational from Québec to the Astoria Annex substation in Queens, New York, this sensitivity scenario considered the project's unavailability and the subsequent contingency measures required by the New York Independent System Operator (NYISO). Consistent with the NYISO contingency preparations and the New York State Peaker Rule, this sensitivity included keeping the Gowanus 2 & 3 and Narrows 1 & 2 generating units in service. These units are planned to be retained as needed to address ongoing local reliability needs in the New York City area that would otherwise be mitigated by the CHPE project. Under these conditions, the assessment determined that the delay would have a minimal impact on overall system reliability, effectively accounting for the interdependence between major transmission timelines and local resource retirement schedules. Detailed results are found below in **Table 20**.

Northern New York Load Pocket Under Stressed Conditions

An additional independent sensitivity case was analyzed using a probabilistic approach focusing on resource adequacy within the Northern New York (NNY) load pocket under stressed conditions. The objective is to evaluate the reliability impacts on the New York Control Area (NYCA) and broader Northeast Power Coordinating Council (NPCC) regions when Northern NY faces a simultaneous loss of intermittent renewables, specific peaker plants, and non-firm imports. For this sensitivity analysis, the 2026 Summer Reliability Base Case was adjusted to simulate an assumed resource scenario by setting all wind and solar output within the NNY load pocket to 0 MW, effectively mimicking a localized intermittent resource deficit or wind lull event during peak demand. Additionally, the Saranac Energy and Sithe-Massena peaker units were adjusted as out-of-service because they lack daily run mandates and cannot be guaranteed for rapid start-up, and finally, imports across the Cedar Rapids interface are reduced to zero to reflect the absence of firm scheduling on that tie-line.

The sensitivity analysis results indicated minor reliability impacts for the NYCA and for their neighboring areas in the NPCC region. The New York system demonstrated sufficient resilience to absorb the loss of these specific NNY resources. This analysis demonstrated that reliability risks during extreme weather conditions—specifically scenarios where renewable pockets produce zero output and local thermal backing is unavailable—did not significantly impact the overall energy deliverability of the system. While there may be localized effects if this scenario were to occur, the New York system still remained below the 0.5 event-days/period threshold for both expected and higher load conditions. Detailed results are found below in **Table 21**.

Base Case	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal/Disc	30-min	IL	10-min	Appeal/Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal/Disc
2021 Load Shape - 50/50 Load																						
May	-	-	-	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.068	0.042	-	-	0.016	0.003	0.002	0.002	-	0.058	0.023	0.008	0.007	0.003	-	-	-	-
Jul	-	-	-	-	0.018	0.009	-	-	0.026	0.008	0.004	0.003	-	0.97	0.028	0.013	0.010	0.005	-	-	-	-
Aug	-	-	-	-	0.058	0.029	-	-	0.016	0.003	0.001	0.001	-	0.155	0.058	0.030	0.026	0.010	-	-	-	-
Sep	-	-	-	-	0.004	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.151	0.082	-	-	0.057	0.013	0.007	0.006	0.001	0.311	0.108	0.051	0.044	0.017	-	-	-	-
2021 Load Shape – Higher Peak Load Levels																						
May	-	-	-	-	0.022	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.398	0.242	0.005	-	0.144	0.037	0.021	0.021	0.003	0.407	0.197	0.088	0.082	0.026	-	-	-	-
Jul	-	-	-	-	0.088	0.040	0.001	-	0.280	0.099	0.049	0.041	0.012	0.938	0.285	0.145	0.123	0.058	-	-	-	-
Aug	-	-	-	-	0.417	0.248	-	-	0.161	0.034	0.017	0.016	0.002	1.410	0.687	0.382	0.350	0.141	-	-	-	-
Sep	-	-	-	-	0.041	0.017	-	-	-	-	-	-	-	0.001	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.965	0.551	0.007	-	0.585	0.170	0.087	0.078	0.016	2.756	1.169	0.614	0.555	0.226	-	-	-	-

Table 20: No CHPE Sensitivity Case Assumptions - Expected Need for Indicated Operating Procedures (event-days/month)

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.

Base Case	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal/Disc	30-min	IL	10-min	Appeal/Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal/Disc
2021 Load Shape - 50/50 Load																						
May	-	-	-	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.068	0.042	-	-	0.016	0.003	0.002	0.002	-	0.074	0.030	0.012	0.010	0.004	-	-	-	-
Jul	-	-	-	-	0.019	0.009	-	-	0.030	0.009	0.004	0.004	-	0.109	0.034	0.016	0.013	0.006	-	-	-	-
Aug	-	-	-	-	0.058	0.029	-	-	0.017	0.003	0.001	0.001	-	0.180	0.074	0.038	0.034	0.014	-	-	-	-
Sep	-	-	-	-	0.004	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.151	0.082	-	-	0.063	0.015	0.007	0.007	0.001	0.363	0.138	0.065	0.057	0.024	-	-	-	-
2021 Load Shape – Higher Peak Load Levels																						
May	-	-	-	-	0.022	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	0.399	0.242	0.005	-	0.155	0.042	0.022	0.021	0.003	0.593	0.307	0.145	0.132	0.047	-	-	-	-
Jul	-	-	-	-	0.088	0.040	0.001	-	0.344	0.120	0.056	0.048	0.013	1.093	0.385	0.180	0.160	0.077	-	-	-	-
Aug	-	-	-	-	0.418	0.249	-	-	0.169	0.036	0.018	0.017	0.002	1.669	0.868	0.500	0.458	0.200	-	-	-	-
Sep	-	-	-	-	0.041	0.017	-	-	-	-	-	-	-	0.001	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.968	0.552	0.007	-	0.669	0.198	0.095	0.087	0.018	3.357	1.559	0.826	0.750	0.324	-	-	-	-

Table 21: NNY Load Pocket Sensitivity Case Assumptions - Expected Need for Indicated Operating Procedures (event-days/month)

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.

NPCC is dedicated to the continued reliability of the Bulk Power System in Northeastern North America.

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