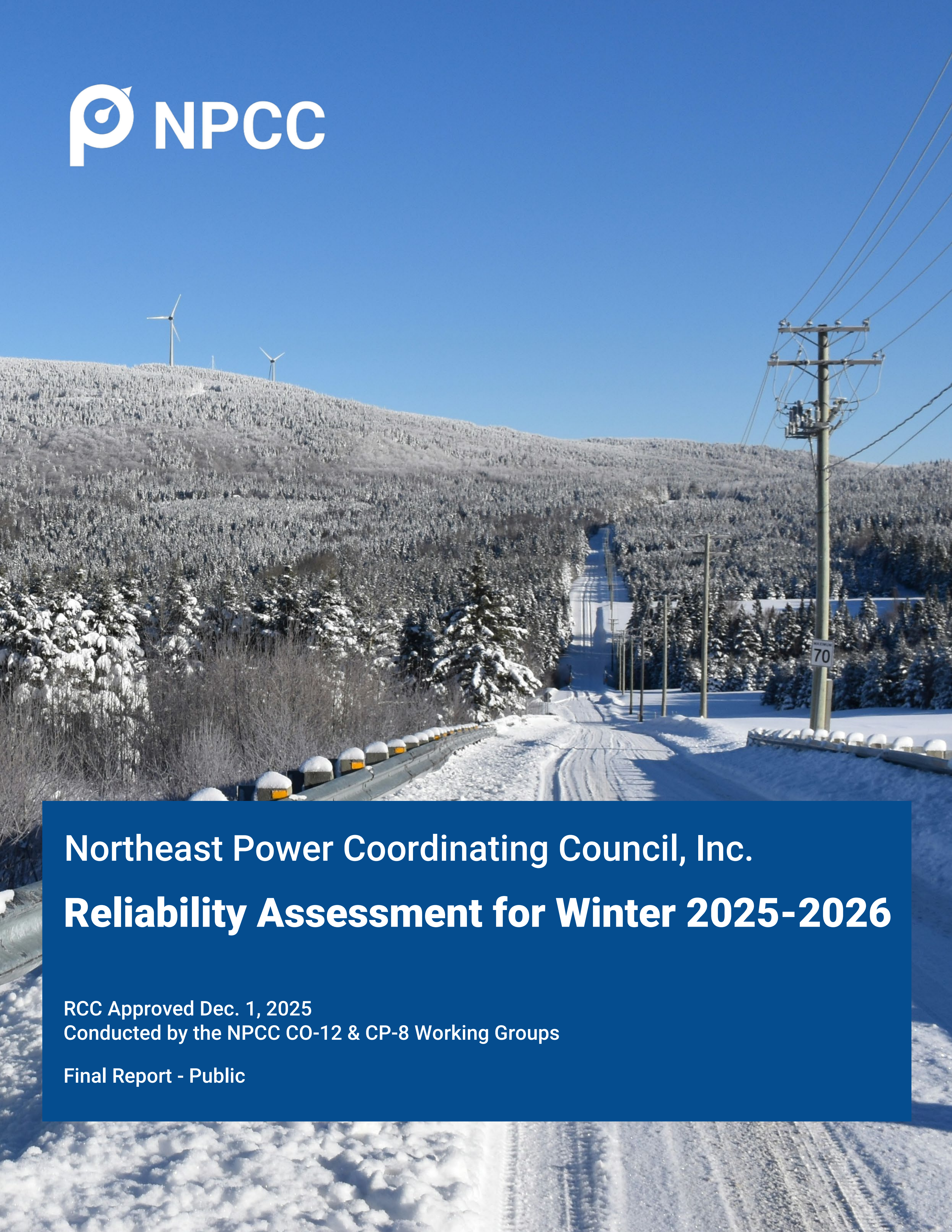

NPCC

Northeast Power Coordinating Council, Inc.

Reliability Assessment for Winter 2025-2026

RCC Approved Dec. 1, 2025
Conducted by the NPCC CO-12 & CP-8 Working Groups

Final Report - Public

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

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1. Executive Summary

This report focuses on the assessment of reliability within NPCC for the 2025-2026 Winter Operating Period 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 winter period, as of October 14, 2025, and can serve as the basis to bracket plausible supply, demand, and operational impacts.

The results of the studies performed by CO-12 (deterministic) and CP-8 (probabilistic) Working Groups indicate that under Base Case conditions, only the Maritimes Area shows a likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads) during the 2025-2026 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven load levels). The results are primarily driven by the Maritimes' forecast load and corresponding reserve margin expectations. While demand and resource levels in the Maritimes are similar to last winter, the elevated Loss of Load Expectation (LOLE) is largely driven by changes in modeling assumptions.[1]

The probabilistic assessment suggests that operators in the Maritimes will likely need to implement emergency operating procedures and/or Emergency Energy Alerts (EEAs) during periods of unusually high demand or reduced resource availability. For the remaining associated Balancing Authority Areas, under low likelihood, high demand severe case conditions, necessary strategies and required procedures are in place to provide load relief and manage operational challenges/emergencies. NPCC's regional peak load has been trending upwards in recent years due to a range of contributing factors. It is important to note that the resource and transmission assessments in this report are mere snapshots in time based off of the most up to date system conditions and assumptions. Results of the NPCC CP-8 Working Group's seasonal, multi-area probabilistic reliability assessment are included in **Section 9** of this report with supporting documentation provided in **Appendix VIII**.

Aspects that the CO-12 Working Group has examined to determine the reliability and adequacy of NPCC for the season are discussed in detail in the specific report sections. The northeast region, notably New England with its constrained natural gas pipeline infrastructure, has significant reliance on global Liquified Natural Gas (LNG) supplies, which are projected to be in high demand this winter. Fuel oil inventories expected entering this winter are at increased risk during periods of extended cold weather. It is critical that

[1] This probabilistic model uses a narrower wind dataset (2020–2024), which lowers expected wind output during peak hours compared to last year's broader range. This is related to an effort to drive consistency between temporal wind output within NPCC Areas in reliability assessments.

generation owners in the region have plans in place to replenish fuel supplies to maintain reliability of the Bulk Electric System.

Meanwhile, low precipitation in northern Québec over 2023-2025 has not significantly affected Québec's winter reliability assessment because Hydro-Québec manages its multi-year reservoirs throughout the year to ensure winter peak power and energy availability.

This report evaluates NPCC's and the associated Balancing Authority (BA) areas' ability to deal with the differing resource and transmission configurations within the NPCC region and the associated Balancing Authority areas' preparations to deal with the possible uncertainties identified within this report.

The forecasted coincident peak demand for the NPCC Region of 112,810 MW is anticipated to occur during the peak week beginning January 18, 2026. The capacity outlook indicates a forecasted net margin for that week of 15,511 MW. This equates to a net margin of 13.7% in terms of the 112,810 MW forecasted peak demand. Winter 2024-2025 in the Northeast region was relatively average with NPCC coincident peak of 107,571 MW compared to the 2022-2023 all-time high NPCC historical winter peak of 112,552 MW. While the forecasted net margin for the NPCC Region is lower (-858 MW) for this upcoming winter compared to the last winter's forecast, driven by a higher forecasted demand (745 MW), the region's spare operable capacity under forecasted conditions[2] through the winter period is estimated to be substantial (capacity over and above reserve requirements) – ranging from approximately 15,511 MW to 25,177 MW.

The Maritimes Area has forecasted a winter peak demand of 6,114 MW for the week beginning January 18, 2026, with a projected net margin of -309 MW (-5.1%). The Maritimes Area shows a cumulative likelihood of using their Operating Procedures (reducing 30-min reserve/Initiate Interruptible Loads) designed to mitigate resource shortages during the 2025-2026 winter period for the Base Case Scenario assuming the 50/50 peak load level.

The New England Area expects to have sufficient resources to meet the 2025-2026 winter peak demand forecast of 20,056 MW, for the weeks beginning January 11 through week beginning January 25, 2026, with the lowest projected net margin of 1,505 MW (7.5%) during the week of January 11. New England additionally studies the 20 most extreme weather events using their Probabilistic Energy Adequacy Tool (PEAT) to determine the region's energy shortfall risk for Winter 2025-2026. The resulting risk is compared to their Regional Energy Shortfall Threshold (REST) criteria. The REST criteria are defined by having an acceptable shortfall magnitude of 3% and an acceptable shortfall duration of 18 hours with a violation occurring only when both magnitude and duration are exceeded. New England's PEAT-based evaluation of extreme events for this winter resulted in shortfall magnitude of 0.1% and shortfall duration of 0.7 hours, both well below the established REST criteria.

[2] Unless otherwise noted, all forecasted demands are 50/50 net peak forecasts.

The New York Area anticipates adequate resources to meet demand for the 2025 Winter Operating Period. The 2025 winter peak forecast is 24,200 MW and anticipated net margins for the expected winter peak period (December 1 through March 30) are at a minimum of 7,634 MW (31.6%).

The forecasted 2025-2026 Ontario winter peak demand is 22,042 MW for 50/50 weather and 23,273 MW for 90/10 weather during the weeks of January 4, 2026, through January 18, 2026. These winter peaks are forecasted on a weekly basis for operational planning and can deviate from winter peaks forecasted on a seasonal basis as per the demand forecast methodology documented in **Appendix IV** for Ontario. The minimum net margin observed during the Winter Operating Period is 2,438 MW, or 6.6% during the week beginning November 30, 2025. Ontario does not anticipate any adequacy concerns this winter.

The Québec Area forecasted winter peak demand is 40,446 MW during the week beginning January 18, 2026, with a forecasted net margin of 443 MW (1.1%). No resource adequacy problems are forecasted.

2. Introduction

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

For the 2025-2026 Winter Operating Period[3] the CO-12 Working Group:

- Examined historical winter operating experiences and assessed their applicability for this period.
- Examined the existing emergency operating procedures available within NPCC and reviewed recent operating procedure additions and revisions.
- Reflected the results of the NPCC CP-8 Working Group probabilistic assessment of the implementation of operating procedures for the 2025-2026 Winter Operating Period in this report. The full CP-8 assessment report is included as **Appendix VIII**.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator (RC) area basis. These sensitivities included 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 both 50/50, 90/10 and Above 90/10 forecasts while accounting for assumed resource outages, derates and bottled capacity within the NPCC region, as requested by the NPCC Task Force on Coordination of Operation.
- 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 (RAS) Seasonal Reliability Assessments.

[3] For this report, the Winter Operating Period evaluation will include operating conditions from the week beginning November 30, 2025, through the week beginning March 31, 2026.

3. Demand Forecasts for Winter 2025-2026

The coincident 50/50 forecasted peak demand for NPCC over the 2025-2026 Winter Operating Period is 112,810 MW, which is expected during the week beginning January 18, 2026. The 50/50 forecasted peak demand for NPCC is 745 MW higher than the previous Winter Operating Period forecast. The NPCC Winter 2024-2025 actual coincident peak demand of 107,681 MW occurred on January 22, 2025, at HE8 EST. It was 4,384 MW lower (3.9%) than the forecasted coincident peak of 112,065 MW. All five NPCC Areas experienced their non-coincident peak demands on January 22, with Maritimes and Québec experiencing morning peaks, and Ontario, New York, and New England experiencing evening peaks. The winter 2024-2025 in the Northeast region was average compared to recent years, with a recorded NPCC coincident peak demand approximately 1,300 MW higher than the average observed in the past 10 years. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in **Appendix I**.

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

In the operational planning timeframe, the impact of ambient weather conditions on load forecasts can be demonstrated by various means.

- The Maritimes and IESO represent the resulting load forecast uncertainty in their respective areas as a mathematical function of the base load.
- ISO-NE updates the load forecast twice daily, on a seven-day time horizon in each forecast. The load forecast models are provided with a weather input of a 23-city weighted average dry bulb temperature, dew point, wind speed, cloud cover and precipitation. Zonal load forecasts are produced for the eight Load Zones across New England using the same weather inputs with different locational weightings.
- The NYISO uses a weather index that relates air temperature and wind speed to the load response and increases the load by a MW factor for each degree below the base value.

- The Québec system operator updates Area forecasts on an hourly basis within a 12-day horizon based on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority area.

Each Reliability Coordinator area uses to determine the peak forecast demands and the associated Load Forecast Uncertainties are described in **Section 4** and **Appendix IV**. Below is a summary of all Reliability Coordinator Area forecasts.

Summary of Reliability Coordinator Area Forecasts

Detailed in **tables 3-1** through **3-5** below are the Reliability Coordinator Area forecasts for the Winters 2025-2026 and 2024-2025. **Figures 3-1** through **3-5** below represent the week-by-week demand profiles of each area's Winter 2025-2026 50/50, 90/10 and Above 90/10 forecasts. The winter historical peak demands by week are also included in the figures with individual Area assumptions noted.

Maritimes

	Winter 2025-2026 Forecasted Peak: week beginning January 25, 2026	**Winter 2024-2025 Forecasted Peak: Week beginning January 12, 2025**	**Winter 2024-2025 Actual Peak: January 22, 2025, at HE09 EST**
50/50	6,114	6,211	5,842
90/10	6,526	6,627	
Above 90/10	6,713	6,818	

Table 3-1: Maritimes Area Forecasts (MW)

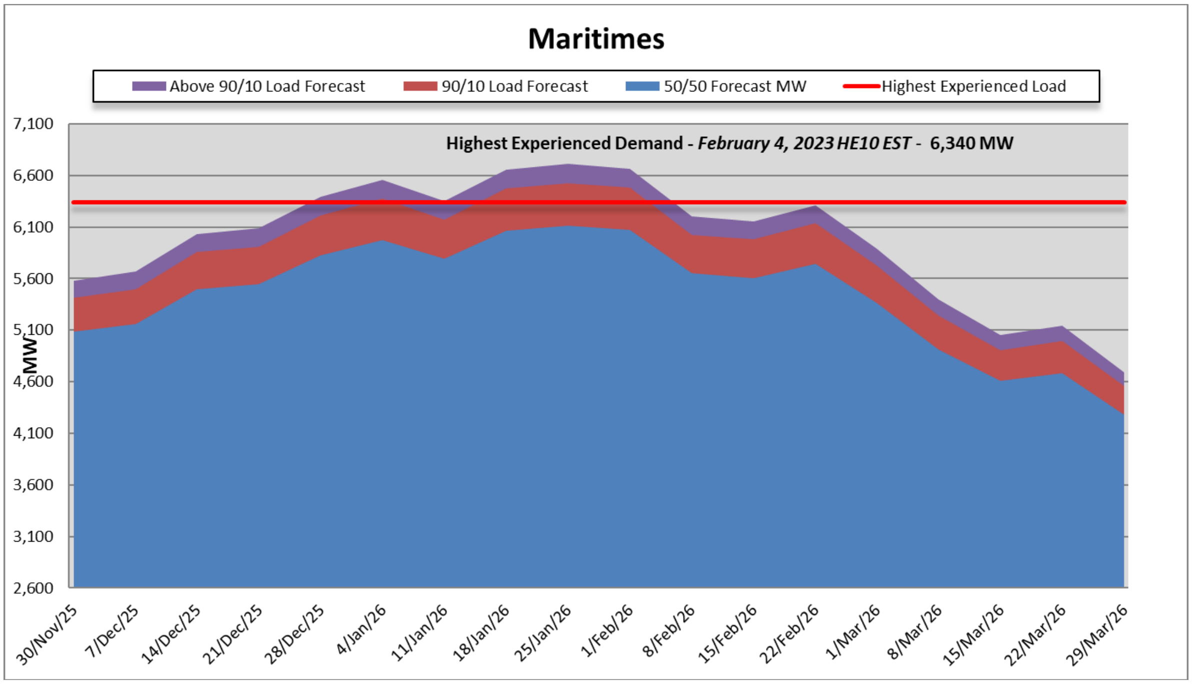

Figure 3-1 Maritimes Winter 2025-2026 Weekly Demand Profile[4]

[4] The Maritimes Area Historical Annual Peak Load provided is based on the historical peak for the years 2004 – 2025.

New England

	Winter 2025-2026 Forecasted Peak: weeks beginning January 11 - 25, 2026	Winter 2024-2025 Forecasted Peak: weeks beginning January 7 - 21, 2025	Winter 2024-2025 Actual Peak: January 22, 2025, at HE18 EST
50/50	20,056	20,308	19,607
90/10	21,125	21,089	
Above 90/10	21,948	21,814	

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

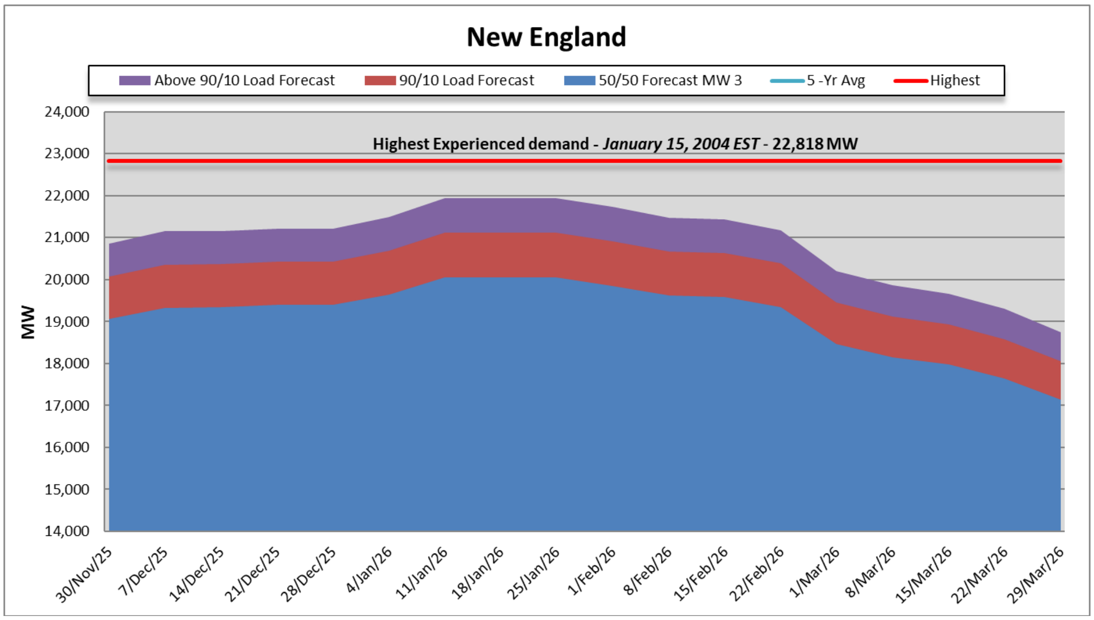

Figure 3-2: New England 2025-2026 Weekly Demand Profile[5] [6]

[5] The winter Peak Load Exposure (PLE) period is three (3) weeks, starting from the first full week of January, not inclusive of the week with the New Year's holiday. The seasonal peak loads are projected in the annual ISO New England Capacity, Energy, Loads, and Transmission (CELT) Report. The forecasted 2025-2026 winter peak demand is during the weeks beginning January 11, 18, and 25, 2026.

[6] The New England Area Historical Peak Load provided is based on the historical peak for the years 2015 - 2025.

New York

	Winter 2025-2026 Forecasted Peak: during weeks of December 14, 2025, through March 8, 2026*	Winter 2024-2025 Forecasted Peak: during weeks of December 8, 2024, through March 9, 2025*	Winter 2024-2025 Actual Peak: January 22, 2025, at HB18 EST
Normal	24,200	23,800	23,521
90/10	25,239	24,825	
Above 90/10	26,281	25,849	

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

**Note: For Winter 2025-2026, it is expected that the New York winter peak could occur at any time during the months of December 2025 through February 2026.*

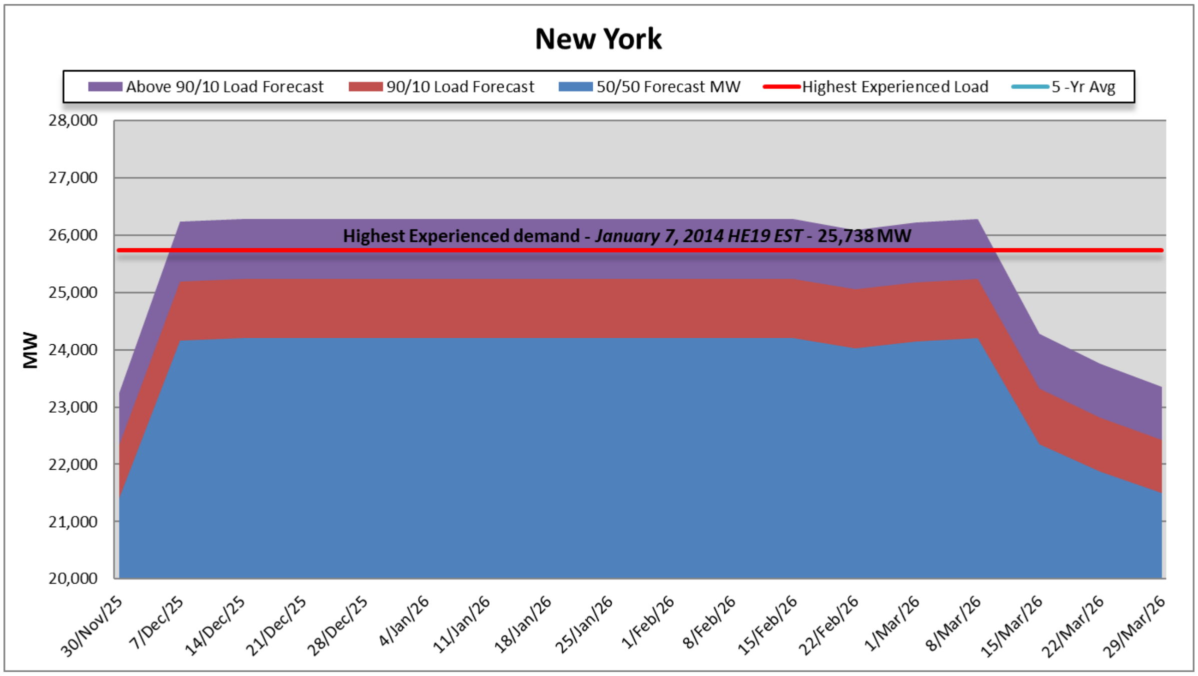

Figure 3-3: New York Winter 2025-2026 Weekly Demand Profile[7]

[7] The New York Area Historical Peak Load provided is based on the historical peak for the years 2006-2025.

Ontario

	Winter 2025-2026 Forecasted Peak during weeks of January 4, 2026, through January 18, 2026	Winter 2024-2025 Forecasted Peak during the week of January 19, 2025	Winter 2024-2025 Actual Peak: January 22, 2025, at HE 18 EST
50/50	22,042	21,898	21,940
90/10	23,164	23,120	
Above 90/10	23,845	23,389	

Table 3-4: Ontario Area Forecasts (MW)

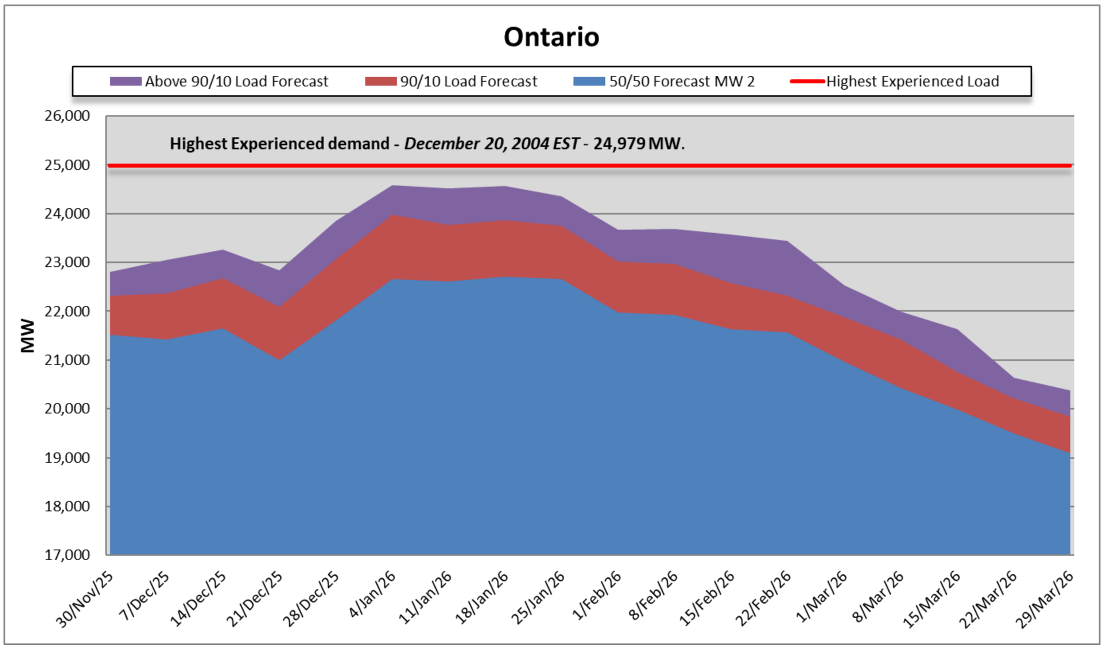

Figure 3-4: Ontario Winter 2025-2026 Weekly Demand Profile[8]

[8] The Ontario Area Historical Weekly Peak Load is based on the historical peak for the years 2002-2025.

Québec

	Winter 2025-2026 Forecasted Peak: week of January 18, 2026	Winter 2024-2025 Forecasted Peak: week of January 26, 2025	Winter 2024-2025 Actual Peak: on January 22, 2025, at HE07 EST
Normal	40,446	40,312	40,015
90/10	42,723	42,618	
Above 90/10	44,019	43,860	

Table 3-5: Québec Area Forecasts (MW)

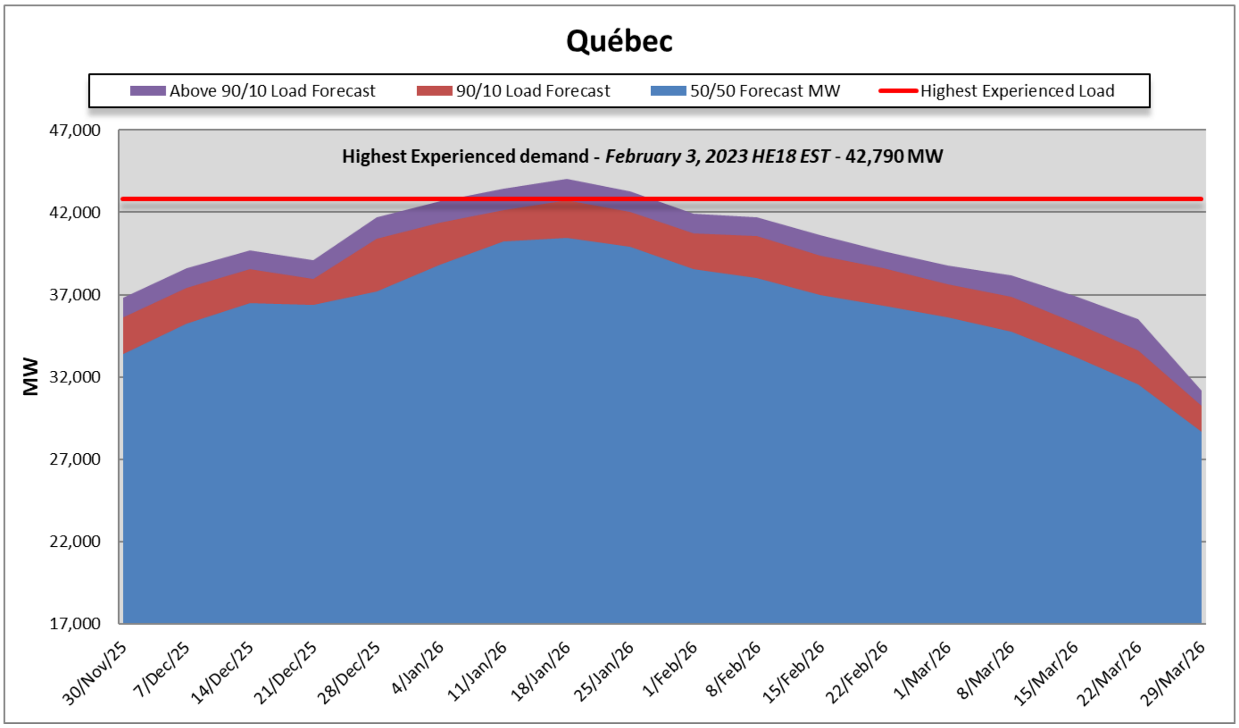

Figure 3-5: Québec Winter 2025-2026 Weekly Demand Profile[9]

[9] The Québec Area Historical Peak Load provided is based on the historical peak for the years 2003-2025.

4. Resource Adequacy

NPCC Summary for Winter 2025-2026

The assessment of resource adequacy indicates the week with the highest forecasted coincident NPCC demand is the week beginning January 18, 2026 (112,810 MW). Detailed projected load and capacity forecast summaries specific to NPCC and each Area are included in **Appendix I**.

In **Appendix I, Table AP-1** is the NPCC (50/50) Load and Capacity summary for the 2025-2026 Winter Operating Period. **Appendix I**, **tables AP-2** through **AP-6**, contains the load and capacity summary for each NPCC Reliability Coordinator area. Each entry in **Table AP-1** is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator areas.

Table 4-1 below summarizes the NPCC forecasted load and resource adequacy for the peak week beginning January 18, 2026, compared to the Winter 2024-2025 forecasted peak week beginning January 26, 2025.

All values in MW	2025-2026	2024-2025	Difference
Installed Capacity	161,426	161,698	-272
Net Interchange*	1,360	1,144	216
Dispatchable Demand-Side Management	2,599	2,234	365
Total Capacity	**165,385**	**165,076**	**309**
Demand	112,810	112,065	745
Interruptible Load	4,623	4,434	189
Maintenance/De-rate	21,721	21,529	192
Required Reserve	8,785	8,580	205
Unplanned Outages	11,182	10,967	215
Net Margin	**15,511**	**16,369**	**-858**
Week Beginning	January 18, 2026	January 26, 2025	-

Table 4-1: Resource Adequacy Comparison of Winter Forecasts

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

The net margin for the 2025-2026 Winter Operating Period has decreased by 858 MW from the previous winter (2024-2025). This can mainly be attributed to an increase in the Demand and decrease in the Installed Capacity.

The NPCC forecasted capacity outlook indicates a coincident peak net margin of 15,511 MW (13.7%) with respect to the 112,810 MW forecasted 50/50 peak demand. When considering 90/10 coincident peak demand, the forecasted 90/10 net margin is 9,595 MW (8.1%).

Table 4-2 below summarizes the NPCC forecasted 50/50 load and resource adequacy for the peak week beginning January 26, 2025, compared to the 90/10 and Above 90/10 forecast scenarios. Reliability Coordinator-specific details, assumptions and methodologies for the forecast analyses are detailed below and **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**.

All values in MW	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity	161,426	161,426	161,426
Net Interchange	1,360	1,360	1,360
Dispatchable DSM	2,599	2,599	2,599
Total Capacity	**165,385**	**165,385**	**165,385**
Demand	112,810	118,725	122,752
Interruptible load	4,623	4,623	4,623
Maintenance/De-rate	21,721	21,721	21,721
Required Reserve	8,785	8,785	8,785
Unplanned Outages	11,182	11,182	20,244
Net Margin	**15,511**	**9,595**	**-3,826**
Bottled Resources	0	0	0
Revised Net Margin	**15,511**	**9,595**	**-3,826**
Week Beginning	18-Jan-26	18-Jan-26	18-Jan-26
Revised Net Margin %	**13.7**	**8.1**	**-3.1**

Table 4-2: Resource Adequacy Comparison of 2025-2026 Winter Forecast Scenarios

The following sections detail the 2025-2026 winter capacity analysis for each Reliability Coordinator Area.

Maritimes

The Maritimes Area declared Installed Capacity is scheduled to be available for the winter period; except for one Hydro generator with a capacity of 101 MW in Nova Scotia. It should also be noted that New Brunswick's largest thermal unit (715 MW gross) is scheduled to return from its outage in December. The net margins calculated include impacting factors such as wind, ambient temperature, and hydro flows that may derate generation and reflect expected out-of-service units. Imports into the Maritimes area are not included unless they have been confirmed as released capacity from their source. Therefore, unless additional forced generator outages were to occur, there would not be any further reduction in the net Installed Capacity. As part of the winter planning process, dual-fueled units will have sufficient supplies of Heavy Fuel Oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions. **Table 4-3** conveys the Maritimes anticipated operable capacity margins for the 50/50, 90/10 and Above 90/10 winter peak load forecasts for the Winter Operating Period.

Winter 2025-2026 – Week of Jan 25	Normal Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	8,137	8,137	8,137
Net Interchange (+)	31	31	31
Dispatchable Demand-Side Management (+)	0	0	0
Total Capacity	**8,168**	**8,168**	**8,168**
Peak Load Forecast (-)	6,114	6,526	6,713
Interruptible Load (+)	254	254	254
Known Maintenance & Derates (-)	1,354	1,354	1,767
Operating Reserve Requirement (-)	934	934	934
Unplanned Outages (-)	329	329	329
Net Margin (MW)	**-309**	**-722**	**-1,320**
Net Margin (%)	**-5.1**	**-11.1**	**-19.7**

Table 4-3: Maritimes Operable Capacity for Winter 2025-2026

If the Maritimes real-time peak demand becomes higher than forecasted, the System Operator may implement operating procedures to maintain system reliability, as outlined in the Maritimes section of Operational Readiness for winter 2025-2026.

Above 90/10 Forecast Assumptions

Above 90/10 forecast assumptions are based on historical data for ambient temperature thermal de-rates and in the extreme case of wind capacity de-rated an additional 50%, coupled with an assumed 50% reduction in natural gas fired generation. 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. Outages are based on historical operating experience.

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** shows the variation in operable capacity margins for the week beginning January 11, 2026, recognizing these factors.

Winter 2025-2026 (SCC) – Week of Jan 11	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Operable Capacity + Non-commercial Capacity	29,367	29,367	29,367
Net Interchange (+)	935	935	935
Dispatchable Demand-Side Management (+)	440	440	440
Total Capacity	**30,742**	**30,742**	**30,742**
Peak Load Forecast (-)	20,056	21,125	21,948
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	804	804	804
Unplanned Outages and Gas at Risk (-)	6,252	7,031	7,966
Operating Reserve Requirement (-)	2,125	2,125	2,125
Net Margin (MW)	**1,505**	**-343**	**-2,101**
Net Margin (%)	**7.5**	**-1.6**	**-9.6**

Table 4-4: New England Installed and Operable Capacity for Winter 2025-2026

ISO-NE also compares the installed capacity with operable capacity for a 90/10 load forecast to further determine New England's capacity risks. This broadened approach helps identify potential capacity concerns for the upcoming winter operating period and prepare for higher demand conditions. This analysis shown for January 2026 shows the further reduction in the operable capacity margin recognizing the associated conditions. If these forecasted winter conditions materialize and generators do not achieve their SCC, New England may need to rely more heavily on import capabilities from neighboring areas, as well as implement emergency operating procedures to maintain system reliability.

Finally, ISO-NE conducts an assessment that compares the installed capacity with operable capacity for an Above 90/10 load forecast to determine New England's capacity risks for system conditions resembling the coldest day observed in the past 30 years. This assessment helps to identify potential capacity concerns for the upcoming winter operating period and prepare for capacity and demand conditions should such conditions occur. Similar to the 90/10 forecast, if the Above 90/10 forecasted winter conditions materialize and generators do not achieve their SCC, New England would need to rely even more heavily on import capabilities from neighboring areas, as well as implement emergency operating procedures to maintain system reliability. An additional aspect to the Above 90/10 case is the inclusion of the possibility that generators would become out of service due to cold temperatures. The temperatures at which generators would no longer be able to start are surveyed prior to the start of winter. The Above 90/10 case is the only case with temperatures that intersect with the reported temperatures where outages would begin.[10] This is included as additional unplanned outages.

Above 90/10 Forecast Assumptions

The Above 90/10 forecasted demand is 21,948 MW with a net margin of -2,101 MW (-9.6 percent). This margin assumes 7,966 MW in unplanned outages and gas at risk MW. 500 MW of additional outages are also included to account for unplanned outages due to cold weather during the coldest weeks of the study.

New York

New York determines its operating margin by comparing the normal seasonal peak forecast with the projected Installed Capacity adjusted for seasonal operating factors. Installed Capacity is based on seasonal Dependable Maximum Net Capability (DMNC), tested seasonally, for all traditional thermal and large hydro generators. Wind generators are counted at nameplate for Installed Capacity and seasonal derates are applied. Dispatchable Demand-Side Management consists of Special Case Resources (SCRs) while Interruptible Load includes NYISO's Emergency Demand Response Program (EDRP). Known Maintenance and Derates includes generator maintenance outages known at the time of this writing and derates for renewable resources such as wind, hydro, solar and refuse based on historical performance data. The NPCC Operating Reserve Requirement for New York is one-and-a-half times the largest single generating source contingency in the New York Control Area (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. Net Interchange is based on projected capacity transactions external to the NYCA. The net capacity purchases for the winter of 2025-2026 have increased due to Hydro-Québec Cedars External Deliverability Rights and Hydro-Québec Chateauguay action sales, while the sales to ISO-NE have increased.

NYISO conducted a loss of gas installed capacity assessment to determine the impact on

[10] Starting with the winter of 2021-2022, ISO-NE has expanded the survey of generators to include the question of what temperature the generator would no longer be able to continue operation. The current survey asks at what temperature the generator would no longer be able to startup.

operating margins should gas shortages arise. It found that 6,307 MW of gas fired generation with non-firm supply are at-risk. Should all this capacity not be available during a peak load time, the projected operating margin would drop from 9,514 MW (39.3%) to 3,208 MW (13.3%).

Above 90/10 Forecast Assumptions

It was assumed the Above 90/10 winter scenario would take the form of an extended cold snap, in which gas security could become a risk factor, like the Winter of 2013-2014, during which the breakdown of the polar vortex in November led to a particularly long and cold season. The Above 90/10 Forecast includes this at-risk generation in the Unplanned Outages category. Should such a scenario materialize, sufficient operating procedures are available to mitigate any capacity shortfall (See **Section 6**).

Table 4-5 below presents a conservative scenario comparing the normal, 90/10 and Above 90/10 operating margins for the upcoming winter period.

Winter 2025-2026 – Week of Jan 18	Normal Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	40,080	40,080	40,080
Net Interchange (+)	1,203	1,203	1,203
Dispatchable Demand-Side Management (+)	1,026	1,026	1,026
Total Capacity	**42,083**	**42,083**	**42,083**
Peak Load Forecast (-)	24,200	25,239	26,281
Interruptible Load (+)	1	1	1
Known Maintenance & Derates (-)	3,550	3,550	3,550
Operating Reserve Requirement (-)	2,620	2,620	2,620
Unplanned Outages (-)	2,426	2,426	8,733
Net Margin (MW)	**9,514**	**8,475**	**1,126**
Net Margin (%)	**39.3**	**33.6**	**4.3**

Table 4-5: New York Operable Capacity Forecast for Winter 2025-2026

Ontario

Looking at the 2025-2026 Winter Operating Period, considering existing and planned capacity coming in-service and/or retirements, the Ontario reserve requirement is met under both 50/50 and 90/10 weather conditions, as indicated in Table 4-6. The 2023

Capacity Sharing Agreement between the IESO and Hydro-Québec permits for the swap of 600 MW of capacity over a period of up to seven years, starting in winter 2024-2025. Under the agreement, the IESO will provide 600 MW to Hydro-Québec in the winter, and Hydro-Québec will provide 600 MW to the IESO in the summer. The IESO may choose to bank any amount of the 600 MW of summer capacity provided each year, to be used in a later summer during the agreement (up to the limit of the main intertie with Québec), allowing capacity to be saved until it is required.

Winter 2025-2026: Week of Jan 18	Normal Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	37,958	37,958	37,958
Net Interchange (+)	-420	-420	-420
Dispatchable Demand-Side Management (+)	868	818	818
Total Capacity	**38,406**	**38,356**	**38,356**
Peak Load Forecast (-)	22,042	23,273	23,871
Known Maintenance & Derates (-)	10,345	9,716	9,716
Operating Reserve Requirement (-)	1,567	1,567	1,567
Unplanned Outages (-)	1,148	1,567	1,567
Net Margin (MW)	**3,304**	**2,233**	**1,455**
Net Margin (%)	**15.0**	**9.6**	**6.1**

Table 4-6: Ontario Operable Capacity Forecast for Winter 2025-2026

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

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 variability of the weather under extreme scenarios taken into consideration.

The results in **Table 4-7** indicate that occurrences of unserved energy are not expected over the winter 2025-2026 period. Based on these results, it is anticipated that Ontario will be energy adequate for the 50/50 weather scenario for the review period.

Month	Forecast Energy Production Capability (GWh)	Forecast Energy Demand (GWh)
Dec 2025	19,308	12,930
Jan 2026	19,741	13,924
Feb 2026	17,547	12,306
Mar 2026	18,815	12,713

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

Québec

The Québec area anticipates adequate resources to meet demand for the Winter Operating Period. The current 2025-2026 peak forecast (50/50) is 40,446 MW and the forecasted operating margin is 433 MW for the area peak week. This includes known maintenance and derates of 5,594 MW, including scheduled generator maintenance and wind generation derating as well as 1,500 MW of Unplanned Outages. **Table 4-8** below shows the factors included in the operating margin calculation. An above 90/10 forecast scenario has also been evaluated and the margin anticipated is -3,030 MW.

Note, the precipitation in Hydro-Québec's northern generation system has been low from 2023 to 2025. If poor precipitation conditions continue through the fall, a few of Hydro-Québec's hydro generators whose power generation is sensitive to reduced reservoir levels could be derated. This reduction of around 200 MW is already accounted for in the deratings. Aside from this derating, the poor precipitation the past three years has little negative impact on winter peak margins because proactive reservoir level management throughout the year ensures sufficient power availability for the winter peak season.

Winter 2025-2026 – Week of Jan 18	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity	45,884	45,884	45,884
Net Interchange	-389	-389	-389
Dispatchable Demand-Side Management (+)	265	265	265
Total Capacity	**45,760**	**45,760**	**45,760**
Peak Load Forecast (-)	40,446	42,723	44,019
Interruptible Load (+)	4,362	4,362	4,362
Known Maintenance & Derates (-)	5,594	5,594	5,594
Operating Reserve Requirement (-)	1,500	1,500	1,500
Unplanned Outages (-)	1,500	1,500	2,000
Net Margin (MW)	**443**	**-1,234**	**-3,030**
Net Margin (%)	**1.1**	**-2.9**	**-6.9**

Table 4-8: Québec Operable Capacity Forecasts for Winter 2025-2026

Above 90/10 Forecast Assumptions

For the Above 90/10 forecast scenario, the 50/50 load forecast is used to which is added two standard deviations of the load forecast uncertainty. This represents a 96/4 forecast scenario. In addition to that, a generation loss of 500 MW is added to the Unplanned Outages, increasing it from 1,500 MW to 2,000 MW.

Québec includes most operational measures in its margins above. If Québec real-time peak demands are higher than forecasted, some measures which are not already included are available to the System Control personnel and are listed in **Section 6**: Operational Readiness.

Projected Capacity Analysis by Reliability Coordinator Area

Table 4-9 below summarizes projected capacity and margins by Reliability Coordinator area. **Appendix I** shows these projections for the entire Winter Operating Period, respecting 50/50 demand forecasts.

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	January 18, 2026	161,426	1,360	2,599	165,385	112,810	4,623	21,721	8,785	11,182	15,511
	NPCC Lowest Revised Net Margin	January 18, 2026	161,426	1,360	2,599	165,385	112,810	4,623	21,721	8,785	11,182	15,511
	NPCC Largest Revised Net Margin	March 22, 2026	161,459	1,360	2,512	165,331	94,667	4,621	34,174	8,619	7,316	25,177
	NPCC Lowest Margin	January 18, 2026	161,426	1,360	2,599	165,385	112,810	4,623	21,721	8,785	11,182	15,511
Maritimes	Peak Week	January 25, 2026	8,137	31	0	8,168	6,114	254	1,354	934	329	-309
	Lowest Net Margin	January 25, 2026	8,137	31	0	8,168	6,114	254	1,354	934	329	-309
	NPCC Peak Week	January 18, 2026	8,137	31	0	8,168	6,066	260	1,354	934	329	-254
New England	Peak Week	January 18, 2026	29,367	935	440	30,742	20,056	0	878	2,125	5,779	1,904
	Lowest Net Margin	January 11, 2026	29,367	935	440	30,742	20,056	0	804	2,125	6,252	1,505
	NPCC Peak Week	January 18, 2026	29,367	935	440	30,742	20,056	0	878	2,125	5,779	1,904
New York	Peak Week	January 18, 2026	40,080	1,203	1,026	42,309	24,200	1	3,550	2,620	2,426	9,514
	Lowest Net Margin	December 7, 2025	40,062	1,203	1,026	42,291	24,157	1	5,591	2,620	2,290	7,634
	NPCC Peak Week	January 18, 2026	40,080	1,203	1,026	42,309	24,200	1	3,550	2,620	2,426	9,514
Ontario	Peak Week	January 18, 2026	37,958	-420	868	38,406	22,042	0	10,345	1,567	1,148	3304.1
	Lowest Net Margin	November 30, 2025	37,840	-420	818	38,237	20,894	0	12,214	1,567	1,124	2,438
	NPCC Peak Week	January 18, 2026	37,958	-420	868	38,406	22,042	0	10,345	1,567	1,148	3,304
Québec	Peak Week	January 18, 2026	45,884	-389	265	45,760	40,446	4,362	5,594	1,539	1,500	443
	Lowest Net Margin	January 18, 2026	45,884	-389	265	45,760	40,446	4,362	5,594	1,539	1,500	443
	NPCC Peak Week	January 18, 2026	45,884	-389	265	45,760	40,446	4,362	5,594	1,539	1,500	443

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

Generation Resource Changes through Winter 2025-2026

Tables 4-10 through **4-14** below lists the recent and anticipated generation resource additions, commissioning delays and retirements. Generation adjustments may be reflected as an increase or decrease in MW output, recognizing changes due to mechanical, environmental or performance audits.

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
Maritimes	Wind	162	Wind	Q4 – 2025
	Other	100	Storage	2025
	Net Total	**262**		

Table 4-10: Maritimes Resource Changes from Winter 2024-2025 through Winter 2025-2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
New England	Litchfield Solar	+20	Solar	Q1 2025
	Leeds Solar	+20	Solar	Q1 2025
	Beaver River Road Solar	+5	Solar	Q2 2025
	Downeast Wind	+126	Wind (Onshore)	Q2 2025
	Carver Battery	+150	Storage	Q2 2026
	Various Storage Projects	+16	Storage	Q2-Q4 2025
	Gravel Pit Solar	+120	Solar	Q3 2025
	Solar Breaker Tank Farm	+11	Solar	Q3 2025
	TPE King Solar	+13	Solar	Q4 2025
	Exeter Renewables	+10	Solar	Q4 2025
	Medway Grid Battery	+250	Storage	Q4 2025
	Merrimack 1 & 2	-476	Coal	Non-Operational Winter 2025-2026
	Middletown 2	-120	Dual Fuel	Non-Operational Winter 2025-2026
	Middletown 3,4, & 10	-669	Oil	Non-Operational Winter 2025-2026
	Doreen	-21	Oil	Q1 2025
	Rutland 5 GT	-15.5	Oil	Q2 2025
	Woodland Road	-21	Oil	Q2 2025
	West Springfield GT ½	-96	Dual Fuel	Q2 2025
	Oak Bluffs	-8.3	Oil	Q4 2025
	West Tisbury	-5.6	Oil	Q4 2025
	Resource Additions	+741		
	Resource Retirements	-167.4		
	Resources Non-Operational	-1,265		
	Net Total	**-691.4**		

Table 4-11: New England Resource Changes from Winter 2024-2025 through Winter 2025-2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
New York	Astoria GT 1	-16	Gas	Q2 – 2025
	Glenwood GT 1	-16	Gas	Q2 – 2025
	West Babylon 4	-52.4	Gas	Q2 – 2025
	Shoreham 2	-18.6	Gas	Q2 – 2025
	59 St GT 1	-17.1	Gas	Q2 – 2025
	Madison Wind Power	-11.6	Wind	Q2 – 2025
	Far Rockaway GT1	-60.5	Gas	Q4 – 2025
	Far Rockaway GT2	-60.5	Gas	Q4 – 2025
	Pinelawn Power 1	-82	Gas	Q4 – 2025
	Arthur Kill Energy Storage	15	Energy Storage	Q2 – 2025
	Magruder BESS	20	Energy Storage	Q2 – 2025
	Flat Hill Solar	20	Solar	Q4 – 2025
	Grassy Knoll Solar	20	Solar	Q4 – 2025
	Yellow Barn Solar	160	Solar	Q4 - 2025
	Clear View Solar	20	Solar	Q4 - 2025
	Transit Solar	20	Solar	Q4 – 2025
	SunEast Scipio Solar	18	Solar	Q4 – 2025
	Calverton Solar	36	Solar	Q4 – 2025
	Highbanks Solar	12.5	Solar	Q1 – 2026
	Total Additions	**+342**		
	Total Retirements	**-335**		
	ICAP Adjustment	**-449**		
	Net Change	**-442**		

Table 4-12: New York Resource Changes from Winter 2024-2025 through Winter 2025-2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
Ontario	Oneida Storage	235	Storage	Q2 2025
	Same Technology Upgrades	286	Gas	Q4 2025
	Expedited Long Term-1 (ELT-1) Projects[11]	203	Storage	Q2 2026
	Seasonal Adjustments	**0**		
	Total Retirements	**0**		
	Net Change	**+724**		

Table 4-13: Ontario Resource Changes from Winter 2024-2025 through Winter 2025-2026

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/ Retirement Date
Québec	Apuait[12]	208	Wind	Q4 2025
	TCE	507	Gas	Q2 2025
	Total Additions	**+208**		
	Total Retirements	**-507**		
	Net Change	**-299**		

Table 4-14: Québec Resource Changes from Winter 2024-2025 through Winter 2025-2026

Maritimes

Since the 2024-2025 Winter Operating Period, there has been a net increase of 354 MW of installed capacity in the Maritimes.

In 2024, Nova Scotia Power identified a need to continue to retain a 148 MW coal-fired unit in cold reserve to provide firm capacity. In 2025, Nova Scotia Power continues to identify a requirement for this firm capacity to maintain adequate planning reserve margin.

[11] Expected final in-service date of March 29, 2026.

[12] Apuait was included in the NPCC 2025-2026 Winter Reliability Assessment, but there were issues with its commissioning during Winter 2024-2025, and it is now expected to come online Q4 2025.

New England

Since the 2024-2025 Winter assessment period, ISO-NE has retired approximately 189 MW of resources which comprises of 96 MW of dual fuel and 93 MW of oil resources. New England introduced roughly 741 MW of new generation; 416 MW of which is from various solar projects. Additionally, there are 1,265 MW of non-operational resources expected for Winter 2025-2026.

New York

Since the 2024-2025 Winter Operating Period, 335 MW of generation was deactivated, along with 449 MW of ICAP Adjustments. However, 342 MW of nameplate capacity has been added.

Ontario

By the end of the 2025-2026 Winter Operating Period, the total capacity in Ontario is expected to increase by 724 MW. This is due to the addition of the Oneida Energy Storage project (235 MW), upgrades to existing gas facilities procured via the Same Technology Upgrades Solicitation (286 MW), and the commissioning of additional battery storage facilities under the ELT-1 Projects.

Québec

The Installed Capacity is estimated at 45,884 MW. This is a decrease from 46,129 MW which reflects the removal from the capacity numbers of a mothballed facility that was 100% derated during the past few years.

Fuel Infrastructure by Reliability Coordinator Area

The following figures (**Figure 4-1** and **Figure 4-2**) depict capacity profiles reported by each Reliability Coordinator Area and for the NPCC Region by fuel supply infrastructure as projected for the NPCC coincident peak week.

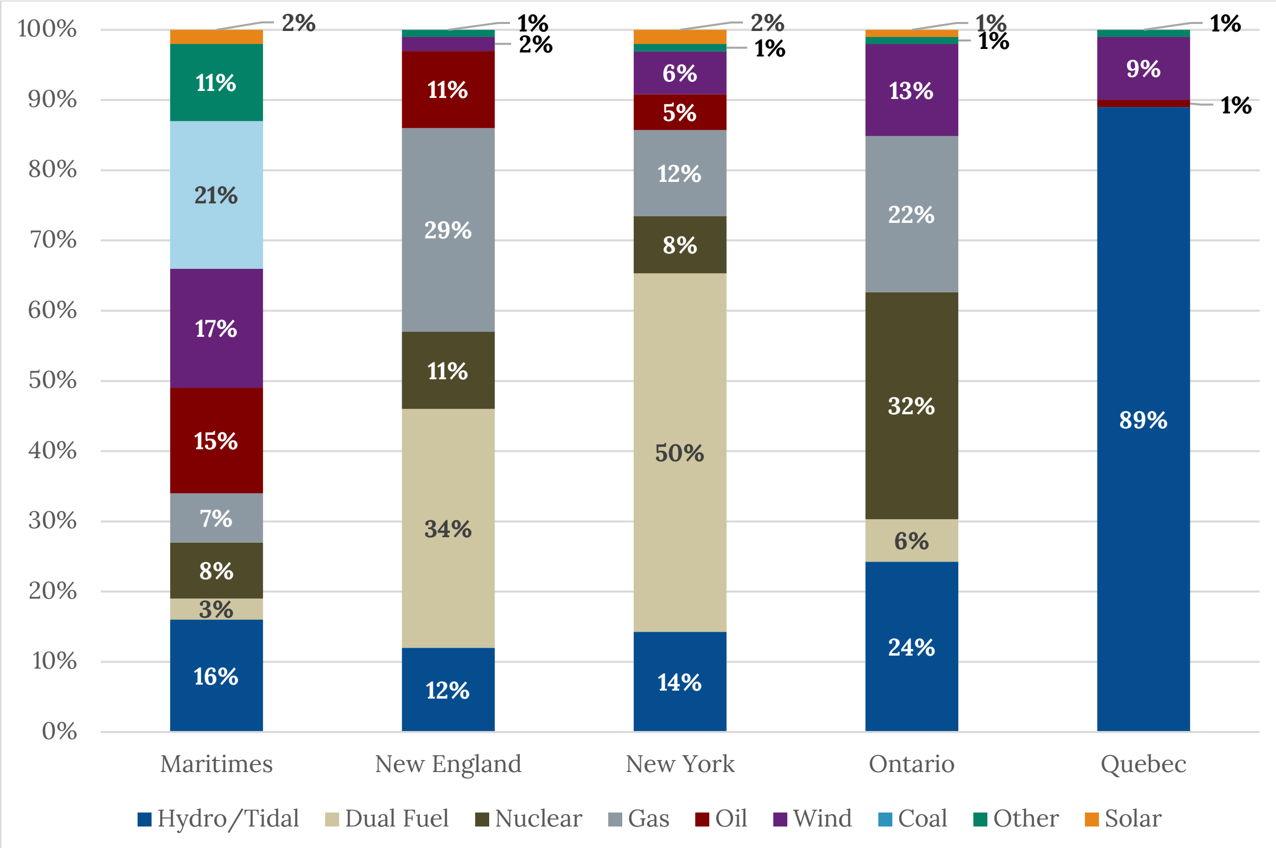

Figure 4-1: Reported Capacity by Fuel Type by Reliability Coordinator Area

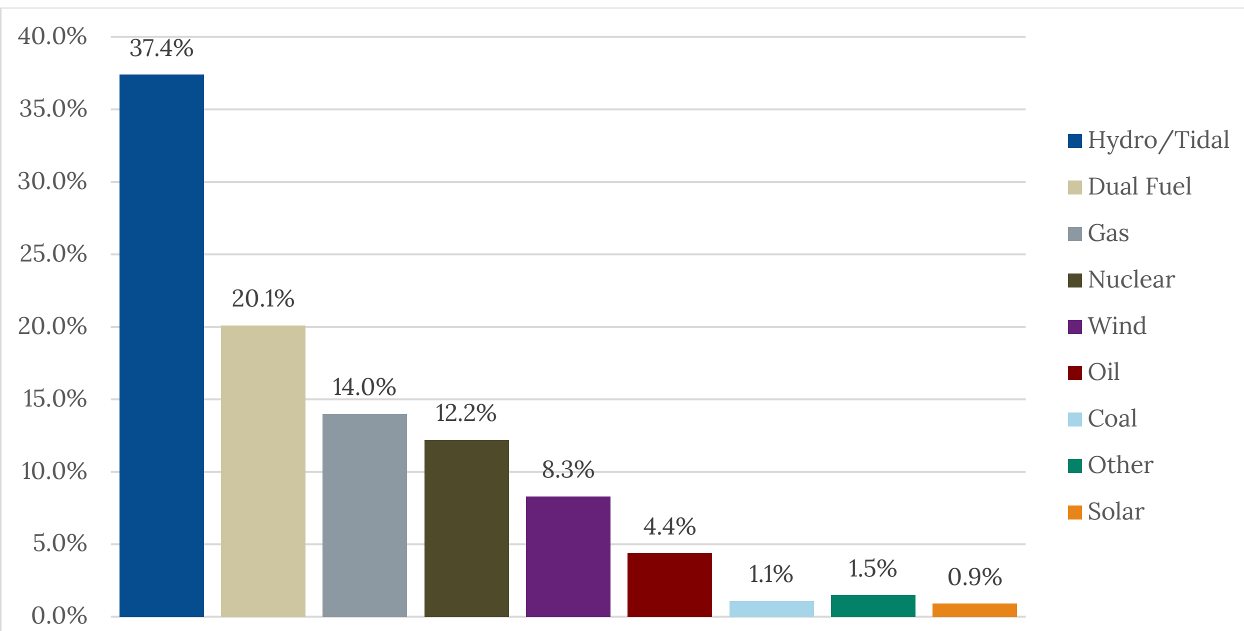

Figure 4-2: Reported Capacity Fuel Profiles for NPCC

Wind and Solar Capacity Analysis by Reliability Coordinator Area

For the upcoming 2025-2026 Winter Operating Period, available installed wind, and solar capacity accounts for approximately 9.2% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 8.3% wind and 0.9% solar. During the winter months, solar capacity is derated to zero for all areas since the peak load is anticipated to occur during non-sunlight hours. 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.

Table 4-15 below illustrates the nameplate of wind, solar and storage capacity in NPCC for the 2025-2026 Winter Operating Period for each of the NPCC Reliability Coordinators. The Maritimes, IESO, NYISO and Québec areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. ISO-NE reduces the nameplate capacity and includes this reduced capacity value directly in the Installed Capacity section of the Load and Capacity Table. Please refer to **Appendix II**, for information on the derating methodology used by each of the NPCC Reliability Coordinators.

Table 4-16 illustrates behind-the-meter solar PV capacity and the amount of impact it has on peak load demand for each area. The IESO, ISO-NE and NYISO each factor in behind-the-meter solar as a peak load reduction. Methodologies for each area can be found in **Appendix IV**.

Reliability Coordinator area	Wind Capacity (including Offshore)	Wind Capacity after derating (including Offshore)	Nameplate Offshore Wind Capacity	Offshore Wind Capacity After Applied Derating Factor	Nameplate Solar Capacity (MW)	Solar Cap After Derating (MW)	Nameplate Energy Storage Capacity (MW)	Energy Storage Cap After Derating (MW)
Maritimes	1,394	350	0	0	147	0	112	78
New England	1,684	455	29	13	3,313	0	382	266
New York*	2,586	678	136	36	627	0	52	0
Ontario	4,943	1,913	0	0	478	66	384	192
Québec	4,024	1,449	0	0	10	0	0	0
Total	**14,631**	**4,845**	**165**	**49**	**4,575**	**66**	**930**	**536**

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

**Total wind nameplate capacity in New York is 2,994 MW; however, only 2,586 MW participates in the ICAP market.*

Reliability Coordinator area	Installed Behind-the-Meter Solar PV (MW)	Impact of BTM Solar PV on Peak Load (MW)
Maritimes	162	0
New England	5,001	0
New York	7,523	0
Ontario	2,170	0
Québec	49	1
Total	**14,905**	**1**

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

Maritimes

In Prince Edward Island, for the wind facilities that have been in production over a three-year period, a derated monthly average is calculated using metering data from previous years over each seasonal assessment period.

The Northern Maine Independent System Administrator (NMISA) uses a fixed capacity derate of 25 MW for the winter assessment period.

New Brunswick and Nova Scotia apply an 18% capacity value to installed wind capacity (82% derated). This figure is based on the Effective Load Carrying Capability (ELCC) of wind determined through a Loss of Load Expectation (LOLE) study. The LOLE study considered multiple years of historical load and wind data and simulated the system under a variety of factors.

New England

During the 2025-2026 winter assessment period, New England derated the 1,684 MW of wind resources by ~73% because of established winter Claimed-Capability Audits (CCAs). Recognizing that wind resources could provide more power than the derated value, ISO New England produces a daily seven-day wind forecast, which provides an aggregate, as well as a wind-plant specific hourly forecast for each hour of the seven-day period. New England additionally derates their 382 MW of storage resources by ~30%. ISO-NE also utilizes system functions and control room displays to improve situational awareness for system operators.

New England continues to observe sustained growth in distributed Photovoltaic (PV) resources. Load reduction from PV can be observed during the midday hours of sunny winter days; however, with the winter peak demand occurring after sunset, ISO-NE fully derates the PV resources.

New York

For the 2025-2026 winter season, there is projected to be 2,994 MW of nameplate wind and 627 MW of nameplate solar installed capacity in New York. The nameplate capacity is counted at full value towards the Installed Capacity for New York and is derated by 74% for wind and 100% for solar based on historical performance data when determining operating margins.

Ontario

The nameplate capacity of transmission connected wind, and solar facilities total 4,943 MW and 478 MW respectively.

For Ontario, monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators at the time of the weekday peak. WCC values in percentage of installed capacity are determined from a combination of 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.

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 at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. A dataset comprising 10 years of simulated solar production history is used for this purpose. As actual solar production data becomes available in future, the process of combining actual historical solar data and the simulated 10-year historical solar data will be incorporated into the SCC methodology, until 10 years of actual solar data is accumulated at which point the use of simulated data will be discontinued.

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

Embedded generation reduces the need for grid-supplied electricity by generating electricity on the distribution system. Since the majority of embedded generation is solar powered, embedded generation is divided into two separate components: solar and non-solar. Non-solar embedded generation includes generation fueled by biogas, 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 model.

Québec

In the Québec area, nameplate wind capacity is 4,024 MW for the 2025-2026 winter peak period, de-rated by 64 percent for an expected 1,449 MW contribution. This derating is checked annually against actual winter production in the previous year. The contribution of wind resources is forecast in operations.

Solar generation capacity is 10 MW with behind-the-meter installed solar generation at 49 MW. However, the contribution to the peak is taken to be near zero as the peak in Québec is often in darkness.

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. **Table 4-17** 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 January 18, 2026. Definitions of the terms are included in **Appendix II** (Load and Capacity Tables definitions).

Reliability Coordinator Area	DDSM Resources (MW)	Interruptible Loads (MW)	Total (MW)
Maritimes	0	260	260
New England	440	0	440
New York	1,026	1	1,027
Ontario	868	0	868
Québec	265	4,362	4,627
Total	**2,599**	**4,623**	**7,222**

Table 4-17: Summary of Forecasted Demand Response Programs

In the Load and Capacity tables presented in **Appendix I**, the Dispatchable Demand-Side Management values are accounted for on the resources side (included in Total Capacity) and the Interruptible Loads values are accounted for on the demand side as load modifier.

The total forecasted 2025-2026 Winter demand response available for NPCC is 7,222 MW, a 478 MW increase from the forecasted 6,744 MW of winter demand response available during 2024-2025.

Maritimes

Interruptible loads are forecast on a weekly basis and range between 246 MW and 280 MW. The values can be found in **Table AP-2** and are available for use when corrective action is required within the Area.

At the time of the winter peak, the impact of demand response and demand-side management is included in the Nova Scotia portion of the load forecast. Demand response programing in New Brunswick is in the early stages of implementation and at this time is not considered in its resource adequacy assessments. This is expected to change once a consistent verification process gets implemented.

New England

In New England, 440 MW of active demand resources are projected to be available on peak for the 2025-2026 winter assessment period. In addition to active demand resources, 2,442 MW of passive demand resources (i.e., energy-efficiency measures and distributed generation) are treated as demand reducers in this report and are accounted for in the load forecast of 20,056 MW. Passive demand measures include installed products, equipment, and systems, as well as services, practices, and strategies, at end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. The amount of energy efficiency is based on capacity supply obligations in the Forward Capacity Market.

New York

NYISO has three demand response programs to support system reliability. NYISO currently projects 1,027 MW of total demand response available for the 2025-2026 winter season.

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

The Installed Capacity (ICAP) Special Case Resource program is categorized as Dispatchable Demand-Side Management. It allows demand resources that meet certification requirements to offer Unforced Capacity (UCAP) to Load Serving Entities (LSEs). The load reduction capability of Special Case Resources (SCRs) may be sold in the ICAP Market just like any other ICAP Resource; however, SCRs participate through Responsible Interface Parties (RIPs), which serve as the interface between the NYISO and the resources. RIPs also act as aggregators of SCRs. SCRs that have sold ICAP are obligated to reduce their system load when called upon by 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 NYISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, RIPs are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources. The total SCR value includes Special Case Resources that have or are expected to transition to the Distributed Energy Resource (DER) aggregation participation model.

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, interruptible loads and demand response capacity procured through the IESO's capacity auctions. 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 embedded generation. The load modifiers are incorporated into the demand forecast.

For the winter assessment period, the capacity of the demand response program consists of 1,106 MW from auctions, 682 MW from dispatchable loads and up to 50 MW from interruptible loads.

Québec

The Québec Area has various types of Demand Response (DR) resources specifically designed for peak shaving during winter operating periods, having an estimated combined impact of 4,937 MW under winter peak conditions (2025-2026).

See **Table 4-18** for the breakdown of the resources:

Resource	MW	Comments
Interruptible industrial load	2,834	Includes a major industrial customer that interrupts load and provides some net generation and some industrial customers with non-firm energy supply.
Large Commercial and Institutional peak load management	930	
Residential peak load management	608	Dynamic rate options for residential and small commercial or institutional customers that are a mix of requirements and incentives
Block chain data centers	280	Required by the rate.
Voltage reduction	265	Accounted in the "Dispatchable Demand-Side Management" column of the Load and Capacity table presented in **Table AP-6**

Table 4-18: Summary of Québec Area Demand Response Programs

All resources are profiled based on their historical performance and their contribution is included in the operators' energy forecasting system.

In addition, Energy Efficiency and Conservation programs are implemented throughout the year by Hydro-Québec and by the provincial government, through its Ministry of Natural Resources. Energy Efficiency and Conservation programs are integrated in the assessment area's demand forecasts.

5. Transmission Adequacy

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

The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels, Inter-Region, Inter-Area, and Intra-Area.

Inter-Regional Transmission Adequacy

Ontario – Manitoba Interconnection

The Ontario – Manitoba interconnection consists of two 230 kV circuits and one 115 kV circuit. The transfers on the 230 kV interconnection points are under the control of Phase Angle Regulators (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 one 115 kV interconnection point. 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 interconnection points, one 230/115 kV interconnection point, and one 230 kV interconnection point. 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 345/230 kV "B" and "C" PAR controlled lines are currently out-of-service and expected to remain so at least through the end of the winter season.

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 5-1** below summarizes the transfer capabilities between Areas:

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	2,200
PJM	2,100
Québec	1,500
Transfer from Ontario to	
MISO	1,650
New York	2,100
Québec	2,165
Transfers from Québec to	
Maritimes	773 + radial loads
New England	3,425
New York	1,999
Ontario	2,705

Table 5-1: Interconnection 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 Winter 2025-2026 Operating Period under expected and peak demand configurations and have provided the following review as well as identified transmission improvements listed in **Table 5-2**.

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	-	-	-
New England	New England Clean Energy Connect (NECEC) (HQ-NE HVDC Tie Line)	345	Q4 2025
	3027 Line (Maine Area Transmission Upgrade	345	Q4 2025
	Buxton STATCOMs (Maine Area Transmission Upgrade	345	Q4 2025
New York	Dover PAR and Station	345	Q4 2025
	Smart Path Connect (SPC)	345, 230	Q4 2025
Ontario	Richview TS x Trafalgar TS: FETT Reinforcement	230	Q1 2026
Québec	NECEC	320	Q4 2025
	Anjou Station	315	Q3 2025

Table 5-2: NPCC – Recent and Future Transmission Additions

Maritimes

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Winter Operating Period. Part of the Total Transfer Capability (TTC) calculation with Québec is based on the ability to transfer radial loads onto the Québec system. The radial load value will be calculated monthly, and Québec 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 Static Synchronous Compensators (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 Bulk Electric System (BES) 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

The Dover 345 kV Phase Angle Regulator will be connected between Cricket Valley and Dover Station on the existing 398 line to Long Mountain Station (ISO-NE) will be in service in the winter.

The Smart Path Connect (SPC) Transmission Upgrade Project upgrades 230 kV buses and stations to new 345 kV rated equipment located in the North zone (Area D) of the NY control area and is undergoing energization during the winter period.

Ontario

For this Winter Operating Period, Ontario's transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmission outages under normal and extreme conditions. Ontario has an expected coincident import capability of approximately 5,200 MW.

Ontario navigates ongoing nuclear refurbishments that challenge the ability for market participants to take outages impacting the Flow East Towards Toronto (FETT) interface. As a result, the Richview TS x Trafalgar TS reinforcement will enhance the West-East flow from resources in Southwest Ontario to improve system adequacy in East Ontario. The project is expected to be in service by Q1 2026.

Outages affecting neighboring jurisdictions can be found in **Table 5-3**: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the winter season.

Québec

Transmission system upgrades in 2025 include the projected commissioning of the NECEC interconnection with ISO-NE in late 2025. Hydro-Québec also added a 315 kV station in the Montreal region.

Area Transmission Outage Assessment

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

Maritimes

There are no scheduled transmission outages on interfaces between Reliability Coordinators.

New England

There are no transmission outages in New England during Winter 2025-2026 that affect Total Transfer Capabilities (TTCs).

New York

There are no transmission outages on interfaces between Reliability Coordinators.

Ontario

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
MISO	B3N	2026/01/06	2026/01/30	400 MW (Export) / 450 MW (Import)
MISO	K21W	2024/05/14	2025/12/31	110 MW (Export) / 110 MW (Import)

Table 5-3: Ontario Area Transmission Outage Assessment

Québec

There are no transmission outages on interfaces between Reliability Coordinators.

6. Operational Readiness for Winter 2025-2026

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 and reliable operations prior to and throughout the Winter 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 with the potential to affect operations are properly reviewed. Whenever adverse system operating or weather conditions are expected or encountered, any Reliability Coordinator (RC) Area or NPCC staff may request an Emergency Preparedness Conference Call to discuss issues related to the adequacy and security of the interconnected BPS with appropriate operations management personnel from the NPCC RC Areas, NPCC staff and neighboring systems. 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 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[13] and procedures[14] requiring entities to mitigate the potential effects of geomagnetic disturbances.

Lastly, NPCC and its Areas support Electric-Gas Operations reliability coordination efforts to promote 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. This is not meant to be a comprehensive list of control actions for each of the areas. The table provided illustrates a potential set of real-time solutions in the event of a low likelihood, high impact scenario as described in **Section 4.**

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[13] See: NERC EOP-010-1, Geomagnetic Disturbance Operations.
[14] See: NPCC C-15, Procedures for Geomagnetic Disturbances Which Affect Electric Power Systems - Microsoft Word - C-15_20070111.doc.

Actions	Maritimes	New England	New York	Ontario	Québec
Allow depletion of Operating Reserve	693	~600	1,310 (30 Min)	473/945	~750
Curtailment of interruptible load	254	-	225	868	already included
Manual Voltage Reduction	N/A	Variable (0 - 375)	12-524	1.3%-1.8%	already included
Curtailment of non-essential Market Participant load	N/A	40	11	-	-
Voluntary curtailment of large LSE customers	N/A	200	14	-	-
Public Appeals	61	300	74	1%	0-600
Additional Actions	N/A	Variable (45 – 2,545), See OP-4 (link)	-	-	600 Import from Ontario in EEA conditions[15]
Total Assumption Range	1,008	1,145 – 4,020	1,646 – 2,159	N/A	750 – 1,350
Lowest Above 90/10 Net Margin Week	**January 25, 2026**	**January 11, 2026**	**December 7, 2025**	**November 30, 2025**	**January 18, 2026**
Lowest Above 90/10 Net Margin MW	**-1,320 (-19.7%)**	**-2,101 (-9.6%)**	**-751 (-2.9%)**	**965 (4.4%)**	**-3,030 (-6.9%)**
Lowest Above 90/10 Net Margin With Real-Time Procedures Relief	**-312 (-4.7%)**	**-956 (-4.4%)**	**1,408 (5.4 %)**	**(N/A)**	**-2,280 (-5.2%)**

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

[15] 600 MW import is not included in margins for the 50/50 scenario, but is accounted for in both 90/10 and Above 90/10 scenarios.

Maritimes

Voltage Control

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

Operational Procedures

The Maritimes area is a winter peaking system and does not anticipate any operational issues. Though margins are negative for expected peak conditions, in the short term, unit maintenance can be rescheduled, and non-firm assistance can be obtained on the day-ahead market. Additionally, mitigating certain demand and outage scenarios could include the following actions:

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

Changes to internal operating conditions (i.e., transmission and or generator outages) are handled with Short Term Operating Procedures (STOP) which outline any special operating conditions.

Winter Preparation

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

New England

New England has adequate generating capacity for the upcoming winter, however constraints on fuel delivery to the region and the continued retirement of fuel-secure generators results in energy security risks. Given the increasing penetration of variable energy resources and the continued reliance on resources with just-in-time fuel supplies, weather, which is more unpredictable and extreme, will be a key factor affecting regional energy availability and related reliability concerns this winter. Aggregate fuel oil inventory is similar to levels prior to Winter 2024-2025 and ISO-NE anticipates additional replenishment prior to winter. The potential for emissions limitations at some dual-fuel units will have to be monitored closely in the event of significant oil burn. In recent years, ISO-NE has undertaken several operational and market-based measures as well as winter reliability programs to enhance regional energy security.

Because natural gas continues to be the predominant fuel source in New England to produce electricity, ISO-NE continues to closely monitor factors affecting the deliverability of natural gas throughout the winter reliability assessment period. Because of the limited supply capability of the natural gas transportation network and the amount of firm demand on the pipelines during cold weather, ISO-NE anticipates the potential for various amounts of gas-only power plants to be unavailable during cold winter weather demand on the regional gas infrastructure and has developed several tools to maintain gas-electric situational awareness. ISO-NE requests that all gas-fired generators confirm adequate gas supply and transportation nominations in order to meet their day-ahead obligations. As needed, ISO-NE would mitigate generator fuel deliverability issues with real-time supplemental commitment of generators from fuels that are not in short supply, followed by the potential use of capacity deficiency and energy emergency procedures.

New England continues to survey fossil-fueled generators on a weekly basis in order to monitor and confirm their current and expected fuel availability throughout the 2025-2026 Winter Operating Period. If conditions require more frequent updates, these surveys may be sent daily.

ISO-NE utilizes a market design that allows for the hourly re-offer of resources up to 30 minutes prior to the start of each hour. This Energy Market Offer Flexibility (EMOF) project provides a market mechanism for the volatility of fuel (primarily natural gas) prices during intraday nomination and scheduling to be reflected in the real-time energy market offers and therefore included in the optimized resource dispatch and Locational Marginal Price (LMP) calculation, as system conditions evolve throughout any given operating day.

While natural gas supply limitations are understood, stored energy by way of fuel inventory is another limitation that is addressed in recent market enhancements. Fuel pricing for stored fuels requires an additional component to resource price schedules that allow Lead Market Participants to adjust offered prices for stored fuels such that future anticipated prices are included. In other words, on-hand oil may have more value several days from the current day due to impending colder weather. ISO-NE therefore allows for the inclusion of an Energy Market Opportunity Cost (EMOC) to improve resource-specific mitigation procedures by calculating an estimated daily opportunity cost for oil and dual fuel resources with limitations on energy production over a seven-day horizon. Since December 3, 2019, this calculation is performed twice per day – once before the close of the Day Ahead market, the second after the Day Ahead market closes.

During the 2025-2026 Winter Operating Period, ISO-NE will continue to participate in weekly NPCC conference calls to share information on current and forecast system operating conditions. ISO-NE will also continue to coordinate and communicate with the regional natural gas industry through various working groups including the Electric Gas Operations Committee (EGOC), the ISO-RTO Council (IRC) Electric Gas Coordination Task Force (EGCTF), and other ad-hoc communications to promote the reliability of the Bulk Electric System (BES).

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

1. Operating Procedure No. 4 (OP 4), Action During a Capacity Deficiency, establishes criteria and guidelines for actions during capacity deficiencies resulting from generator and transmission contingencies and prescribes actions to manage operating-reserve requirements.[16]

2. Operating Procedure No. 7 (OP 7), Action in an Emergency, establishes criteria to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or any other emergency ISO-NE deems needing resolution through an appropriate action in either an isolated or widespread area of New England.[17]

3. Operating Produce No. 21 (OP 21), Operational Surveys, Energy Forecasting & Reporting and Actions During and Energy Emergency, helps mitigate the adverse impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel-supply deficiencies that can occur anytime.[18] Fuel-supply deficiencies are the temporary or prolonged disruption to regional fuel-supply chains for coal, natural gas, Liquefied Natural Gas (LNG), and heavy and light fuel oil.

OP 21 was modified in the fall of 2018 to allow for an enhanced energy-alert procedure, which includes the following:

- Development of an energy forecasting and reporting framework to establish energy-alert thresholds based on an energy assessment over the next 21 days of operation that includes fuel availability and allowable emissions availability, as well as the anticipated availability of fuel infrastructure and supplies.

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[16] ISO New England, Operating Procedure No. 4, *Action During a Capacity Deficiency* (November 20, 2024), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.
[17] ISO New England, Operating Procedure No. 7, *Action in an Emergency*, (October 1, 2025), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.
[18] ISO New England, Operating Procedure No. 21, *Operational Surveys, Energy Forecasting & Reporting and Actions During and Energy Emergency*, (October 15, 2025), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

- Use of the forecasting and reporting process to inform the declaration of Energy Alerts and Energy Emergencies, which would allow for proactive responses in advance of an Energy Emergency declaration.

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's (NYSRC) Installed Reserve Margin (IRM) of 24.4% for the 2025-2026 winter season.

No unique operational problems were observed from NYISO capability assessment studies. 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, NYISO communicates to neighboring control areas both the capacity-backed import and export transactions that are expected for the NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2025-2026 winter season, the New York Balancing Authority expects to have 1,203 MW of net import capacity available.

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

NYISO is monitoring the potential for natural gas supplies to electric generators to be affected by natural gas infrastructure maintenance, disruptions, availability, etc. communicated via Critical notices. Potential risk to the Bulk Power System is mitigated by extensive dual-fuel generator capability. Generator preparations are informed by prior winter experience and include increased on-site fuel reserves, firm contracts with suppliers of back-up fuel, aggressive replenishment plans, and proactive pre-winter maintenance.

In addition to the resources evaluated hitherto, Emergency Operating Procedures are available to provide up to 2,159 MW of resources should the need arise. Reducing Operating Reserves to zero is also an option in extenuating circumstances to avoid load shedding.

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 peak hours. Wholesale market energy storage does not reduce peak load. This winter, behind-the-meter storage is not forecasted to reduce peak demand.

Winter Readiness

The NYISO Market Mitigation and Analysis Department visits generating stations around the state annually to meet with site personnel, review past performance and assess future readiness. Topics of discussion included past winter operations and preparations for winter 2025-2026. Sites were chosen based on recency of previous visits and potential system impact. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, causes of failed starts, programs to improve performance, cold weather preparations, and potential staffing challenges. They found that generating stations in general have been exposed to enough cold weather events to have implemented many lessons learned to minimize potential mechanical issues. However, there is increasing concern about the current and future demands on the existing natural gas supply system given the increased reliance on natural gas in the northeast US generation fleet and the push towards electrification and decarbonization.

The NYISO conducts a Generator Fuel and Emissions Reporting survey. This survey is sent to all generators and assesses their primary and secondary fuel inventories. This survey is sent prior to the winter season to get baseline numbers and then on a weekly basis during the winter operating period. In addition, the survey is sent on days in which extreme temperatures are forecast, in order to enhance real-time situational awareness. The survey allows operators to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day.

Gas-Electric Coordination

Enhanced Operator visualization of the gas system is in place in the NYISO Control Center. Weekly and daily dashboards are issued during cold weather conditions indicating fuel and capacity margin status. An emergency communication protocol is in place to communicate electric reliability concerns to pipelines and gas distribution centers during tight electric operating conditions.

NYISO conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 6,307 MW of gas fired generation with non-firm supply are at risk.

NYISO continues to participate in various gas-electric industry groups along with the State and Federal agencies, with efforts focused on improving gas-electric coordination to enhance reliability and availability of gas fueled units in the future. NYISO is also considering potential market changes to provide incentives to generators to maintain firm fuel availability.

Ontario

Outage Management

While the IESO fully expects to have sufficient margins for the upcoming season, it continues to carefully manage outages (both generation and transmission) with participants to not only meet global adequacy needs but transmission adequacy and security as well.

Operating Procedures

Ontario expects to have sufficient electricity to meet its forecasted demand. To prepare for the peak seasons, the IESO meets with gas pipeline operators every six months to discuss gas supply and planned maintenance on the gas and electric systems. Since winter 2015-16, the IESO has formalized a Unit Readiness program that exercises units which have been offline for a significant length of time to ensure their readiness for peak periods.

Québec

90/10 load weather and 90/10 temperatures

90/10 and above 90/10 cold weather results in a large load pickup over the 50/50 demand forecast. This situation is addressed at the planning stage through Hydro-Québec's Transmission Design Criteria. When designing the system, one particular criterion requires that both steady state and stability assessments be made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast. This is equivalent to 110% of normal peak winter demand. This ensures that the system is designed to carry the resulting transfers while conforming to all design criteria. Resources needed to serve the load during such episodes must be planned and provided by Hydro-Québec, the Load Serving Entity.

The winter assessment already includes operational measures such as:

- Use of interruptible load
- Voltage reduction
- Operating hydro generating units at their maximum capacity rather than at the optimal efficiency

On an operations horizon, if margins during peak hours are unacceptably low, a number of additional measures are available to the System Control personnel including:

- Imports with neighboring systems
- Operation of hydro generating units with uneconomic spillage
- Reducing 30-minute reserve and stability reserve
- Limitations on non-guaranteed wheel through and export transactions
- Making public appeals
- Ultimately, using cyclic load shedding to maintain system stability and re-establish reserves

A large proportion of the Québec area's hydro generators are located in the north of the province. Specific design requirements are implemented to ensure that cold temperatures do not affect operations. In case of any issues that might arise in real time, maintenance notices are issued to operators to handle such concerns.

Furthermore, Hydro-Québec ensures that maintenance on generating units is finished by December 1, and that all possible generation is available.

Voltage Control

Voltage support in the southern part of the system (load area) might be a concern during Winter Operating Periods during load ramping, especially during episodes of heavy load. This is a known issue for Operations and different initiatives were undertaken in the past to improve monitoring and management of the voltage in the southern part of the system and other initiatives are underway to further improve monitoring and management.

Voltage variations on the high voltage transmission system are also of some concern. These are normal variations due to changes in transmitted power from North to South during load pickup and interconnection ramping. This is also a known issue with solutions already deployed. Nevertheless, the issue is still monitored.

Winter 2025-2026 Solar Terrestrial Dispatch[19] Forecast of Geomagnetically Induced Current (GIC)

Solar Activity Forecast Discussion – October 2025

As shown in **Figure 6-1**, the sunspot number for solar cycle 25 appears to have peaked in October of 2024. The smoothed sunspot number in October was well above most of the model values that were predicted for this sunspot cycle. Note that there is a possibility of a double-peak in the current solar cycle. Some sunspot cycles exhibit this trait.

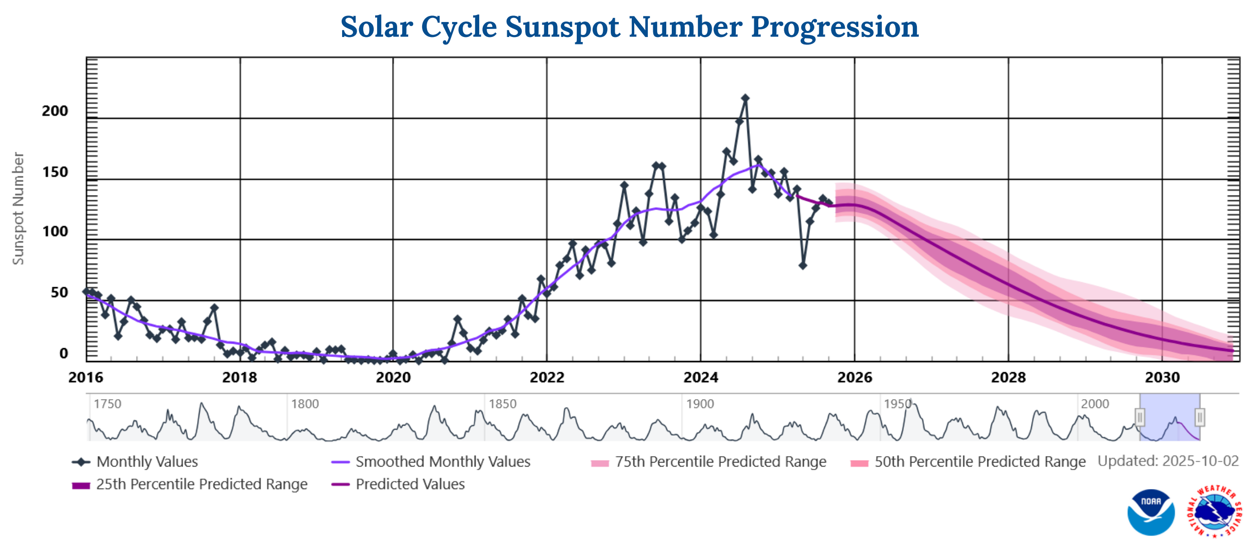

Figure 6-1: Solar Cycle Sunspot Number Progression

The sunspot cycle prediction from the Space Weather Prediction Center (SWPC)[20] is shown in the chart above. The blue trace represents the smoothed sunspot number used by the model, while the black line shows the monthly observed sunspot numbers, which naturally fluctuate around the smoothed curve. The colored gradients correspond to different percentiles of possible smoothed sunspot numbers.

Solar activity will remain at significant levels through the next year. Importantly, the geomagnetic activity maximum has yet to be observed. The geomagnetic activity maximum typically lags the sunspot maximum by about 2 years. NPCC will continue to observe it within the next year or year and a half.

Some of the most intense geomagnetic storms occur during the declining phases of solar cycles, because the sources of strong solar flares (sunspots) and their accompanying coronal

[19] See: Solar Terrestrial Dispatch (spacew.com).
[20] Space Weather Prediction Center: swpc.noaa.gov.

mass ejections migrate towards the equator as the solar cycle progresses. Sources that are closer to the solar equator will have trajectories more directly at the Earth.

Figure 6-2 shows current progression into the geomagnetic activity cycle as provided by Solar Terrestrial Dispatch, which can be directly compared with the sunspot cycle and the frequency of Coronal Mass Ejections (CMEs).

Normalized Smoothed Sunspot, Geomagnetic and CME Activity Cycles

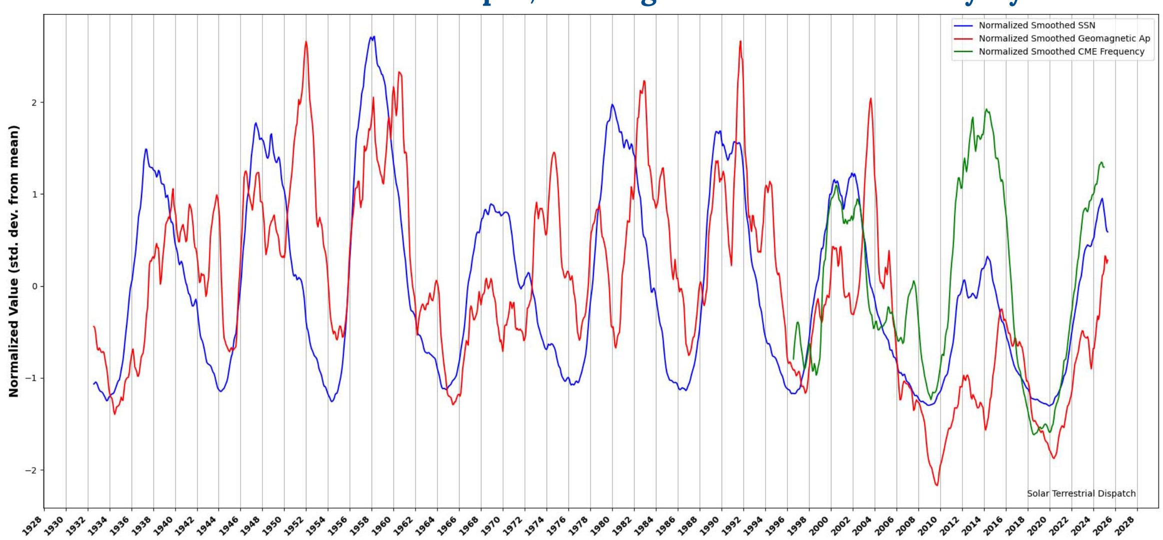

Figure 6-2: Normalized Smoothed Sunspot, Geomagnetic, and CME Activity Cycles

In **Figure 6-2**, 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 Solar and Heliospheric Observatory satellite/Large Angle and Spectrometric Coronagraph Experiment (SOHO/LASCO) team.[21] 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 and peaks in geomagnetic activity.

As can be seen, six of the last eight solar cycles have seen fairly substantial peaks of geomagnetic activity (the red plot line) during the declining phases of the solar sunspot number cycle (the blue lines). A similar trend is predicted to occur for the current solar cycle.

This means that sometime over the next year or two, effects of significant coronal mass ejections associated with major solar flares and developing coronal hole activity could be

[21] 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.

observed. Coronal holes are open areas of the suns magnetic field that allow high velocity solar winds to escape the Sun. These high velocity streams can cause minor to severe geomagnetic storming. Geomagnetically induced currents on power grids will become an increasing concern as we ramp up towards the geomagnetic activity maximum.

Over the fall and winter months of 2025 and into early 2026, coronal holes will heighten geomagnetic activity lasting several days. At the present time, predictions estimate coronal hole effects will be observed on or near the following dates:

- October 12-15
- October 26-29
- November 8-11
- November 22-25
- December 5-8
- December 19-22
- January 1-4, 2026
- January 15-18, 2026
- February 11-14, 2026

The strength of the geomagnetic activity during these periods cannot be reliably predicted in advance, but prior solar rotations have demonstrated that these coronal holes can produce periods of minor to severe geomagnetic activity.

As time progresses, these dates may become less accurate if the boundaries of the coronal holes change. Coronal holes are often fairly stable, but during this phase of the solar cycle, they can evolve rapidly, which would affect the predicted dates.

The periods near October 26, November 22, and December 19 might have somewhat stronger effects than the periods near October 12, November 8, December 5, and January 1. Each of these periods of time should be considered as possible dates for GIC activity on power grids.

Operators are encouraged to monitor daily geomagnetic activity predictions this fall and winter. Because coronal mass ejections cannot be predicted far in advance, accurate long-term forecasting is not possible for these types of phenomena.

NPCC continues to be prepared for a gradually increasing number of severe geomagnetic storm intervals this fall and winter and into 2026, which could be accompanied by varying intensities of GIC activity on power grids.

7. Post-Seasonal and Historical Review

Winter 2024-2025 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator area's winter 2024-2025 operational experiences.

NPCC's coincident peak of 107,571 MW occurred on January 22, 2025, Hour Ending (HE) 08 EST. It was 4,494 MW lower (4.0%) than the forecasted coincident peak of 112,065 MW. The winter 2024-2025 in the Northeast region was relatively average compared to recent years, with an NPCC coincident peak demand just above the average coincident peak demand observed in the past 10 years. This represents a change from the previous two seasons, as winter 2023-2024 was the lowest observed coincident peak demand observed in the past 10 years, and winter 2022-2023 was the record high NPCC coincident winter peak demand. All NPCC Areas experienced their respective winter peaks on January 22, 2025, with Maritimes and Québec experiencing morning peaks, and New England, New York, and Ontario experiencing evening peaks.

Maritimes

The Maritimes system demand during the NPCC coincident peak was 5,612 MW. Maritimes actual peak was 5,842 MW on January 22, 2025, at HE08 EST. Overall, the 2024-2025 winter period was relatively mild for the Maritimes and the actual peak demand was 352 MW (6%) below the 50/50 peak demand forecast. During the 2024-2025 winter period, available capacity in Nova Scotia was below its target planning reserve margin due to a generator refurbishment project that extended beyond its planned completion date, as shown in the 2024-2025 NERC and NPCC Winter Reliability Assessments. As such, during events where in-province generators experienced unforced outages or imports were limited due to constraints with interconnections, multiple Energy Emergency Alerts (EEA) were triggered.

New England

The New England system actual peak demand of 19,607 MW occurred on January 22, 2025, at HE18 EST. Due to an overall milder winter weather pattern, ISO-NE did not experience any extended cold weather days and was not required to issue any Energy Alerts of Energy Emergencies per OP 21 or declare any capacity deficiencies per OP 4.

New York

The actual peak demand of 23,521 MW occurred on January 22, 2025, at Hour Beginning (HB) 18.

During the 2024-2025 Winter Operating Period, NYISO did not experience transmission or reactive capability issues and was not required to utilize firm load shedding or emergency operating procedures. NYISO did experience below normal temperatures, though the system remained below the 50/50 forecast due to day-ahead activation of EDRP/SCR on January 21 and 22, reducing system load by approximately 500-600 MW.

Ontario

The actual peak demand was 21,940 MW on January 22, 2025, at HE18 EST. This was higher than the originally forecasted winter peak of 21,898 MW. There were no significant operational issues observed during the 2024-2025 Winter Operating Period.

Québec

During the NPCC coincident peak, Québec demand was 38,943 MW and the actual peak demand of 40,015 MW occurred at HE08 the morning of the same day.

Total demand response was 3,987 MW.

At the time of the Québec peak, exports of 1,102 MW and imports of 1,975 MW resulted in a net import (including losses) of 744 MW.

Historical Winter Demand Review

Table 7-1 below summarizes the actual historical non-coincident winter peak demands for each NPCC Balancing Authority area over the last ten years along with the forecasted 50/50 coincident peak demand for Winter 2025-2026. Highlighted values are recording high demand that occurred during the NPCC Winter Operating Period over the last 10 years.

Winter	Maritimes	New England	New York	Ontario	Québec	NPCC Coincident Demand	NPCC Coincident Demand Date
2015-2016	5,237	19,545	23,317	20,836	37,650	102,466	February 15, 2016
2016-2017	5,418	19,647	24,164	20,688	37,200	104,335	December 16, 2016
2017-2018	5,344	20,631	25,081	20,906	38,410	109,117	January 5, 2018
2018-2019	5,265	20,719	24,728	21,525	38,364	109,218	January 21, 2019
2019-2020	5,335	18,913	23,253	20,974	36,160	103,969	December 19, 2019
2020-2021	4,928	18,756	22,541	20,738	36,677	102,773	December 16, 2020
2021-2022	5,733	19,623	23,237	21,349	40,410	109,021	January 11, 2022
2022-2023	6,340	19,529	23,369	21,388	42,790	112,552	February 3, 2023
2023-2024	5,511	18,299	22,754	20,880	36,346	101,539	January 19, 2024
2024-2025	5,842	19,607	23,521	21,940	40,015	107,571	January 22, 2025
2025-2026 Forecasted	6,114	20,056	24,200	22,042	40,446	112,810	January 18, 2026

Table 7-1: Ten Year Historical Winter Peak Demands (MW)

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

Reliability Coordinator Area	Load (MW)	Date and time
Maritimes	6,340	February 4, 2023, HE10 EST
New England	22,818	January 15, 2004, HE19 EST
New York	25,738	January 7, 2014, HE19 EST
Ontario	24,979	December 20, 2004, HE18 EST
Québec	42,790	February 3, 2023, HE18 EST

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

8. 2025-2026 Winter Reliability Assessments of Adjacent Regions

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

https://www.rfirst.org/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 2025-2026 Winter 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 November 2025 through March 2026 period. Please refer to **Appendix VIII** (**Table 9**) for a description of the Base Case and Severe Case Assumptions.

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case conditions assuming the 50/50 peak load level, only the Maritimes and Québec Areas show a likelihood greater than 0.5 days/period of using their operating procedures designed to mitigate resource shortages[22] (activation of Demand Response for Québec and reducing 30-min and 10-min reserves and initiating interruptible loads for Maritimes) during the 2025-2026 winter covering the period of November through March. The established Operating Procedures in Québec and the Maritimes are expected to be sufficient to maintain the balance between electricity supply and 50/50 forecast demand should resource shortages arise during the winter period. Occurrences less than 0.5 days per period are not considered significant.

The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated.

Higher Peak Load Levels

Under highest peak load levels, the likelihood of activating emergency procedures increases. The Maritimes Area shows a notable likelihood of utilizing its Operating Procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves, public appeals and disconnecting firm load to maintain system reliability during the upcoming winter period. The Maritimes and Québec have varying reliance on external assistance during the winter 2025-2026 period for the base case higher peak load levels.

The higher peak 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.

[22] Likelihoods of less than 0.5 days/period are not considered significant.

Severe Case Scenario Summary

50/50 Peak Load Level

The Maritimes and Québec Areas show a cumulative likelihood of reducing their 30-min reserve requirements. Further, the Maritimes Area shows a greater cumulative likelihood of using more of their Operating Procedures designed to mitigate resource shortages during the 2025-2026 winter period covering the period November through March. This assessment suggests that operators in the Maritimes will likely need to implement emergency operating procedures and/or Emergency Energy Alerts (EEAs) during periods of unusually high demand or reduced resource availability. The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated.

Higher Peak Load Levels

For the higher load levels, the Maritimes and Québec Areas show greater cumulative likelihoods of using more of their Operating Procedures designed to mitigate resource shortages during the 2025-2026 winter covering the period November through March. Maritimes, Québec, and Ontario have an increased, varying reliance on external assistance during the winter 2025-2026 period. These results are primarily driven by increase in demand forecast due to hitting load.

These highest peak load conditions represent a combined probability of approximately 7%, highlighting potential risks under rare but severe system stress events.

Appendix I - Winter 2025-2026 50/50 Load and Capacity Forecasts

Table AP-1 - NPCC Summary

Area NPCC
Revision Date October 14, 2025

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 %
30/Nov/25	161,191	1,360	2,519	165,069	99,836	4,643	30,321	8,479	8,582	38,904	22,494	**22.5%**	21,058	**21.1%**
7/Dec/25	161,259	1,360	2,527	165,146	104,695	4,628	26,884	8,785	9,616	36,501	19,793	**18.9%**	19,793	**18.9%**
14/Dec/25	161,259	1,360	2,532	165,151	106,519	4,626	24,615	8,785	11,126	35,742	18,731	**17.6%**	18,731	**17.6%**
21/Dec/25	161,259	1,360	2,532	165,151	105,889	4,627	23,985	8,785	11,455	35,440	19,664	**18.6%**	19,664	**18.6%**
28/Dec/25	161,327	1,360	2,535	165,222	107,791	4,609	21,746	8,785	12,046	33,792	19,463	**18.1%**	19,463	**18.1%**
4/Jan/26	161,426	1,360	2,542	165,328	110,621	4,622	21,111	8,785	11,816	32,928	17,617	**15.9%**	17,617	**15.9%**
11/Jan/26	161,426	1,360	2,548	165,334	112,205	4,624	21,046	8,785	11,693	32,738	16,229	**14.5%**	16,229	**14.5%**
18/Jan/26	161,426	1,360	2,599	165,385	112,810	4,623	21,721	8,785	11,182	32,902	15,511	**13.7%**	15,511	**13.7%**
25/Jan/26	161,426	1,360	2,547	165,333	112,264	4,617	22,174	8,619	10,868	33,042	16,025	**14.3%**	16,025	**14.3%**
1/Feb/26	161,439	1,360	2,541	165,340	109,995	4,622	22,316	8,619	11,069	33,385	17,963	**16.3%**	17,963	**16.3%**
8/Feb/26	161,439	1,360	2,539	165,338	108,778	4,626	22,136	8,619	10,932	33,068	19,498	**17.9%**	19,498	**17.9%**
15/Feb/26	161,439	1,360	2,584	165,383	107,369	4,624	22,220	8,619	10,394	32,615	21,404	**19.9%**	21,404	**19.9%**
22/Feb/26	161,439	1,360	2,532	165,331	106,385	4,619	22,317	8,619	10,020	32,337	22,610	**21.3%**	22,610	**21.3%**
1/Mar/26	161,459	1,360	2,529	165,348	103,942	4,619	26,118	8,619	7,593	33,712	23,694	**22.8%**	23,694	**22.8%**
8/Mar/26	161,459	1,360	2,525	165,344	101,840	4,619	29,538	8,619	7,453	36,990	22,513	**22.1%**	22,513	**22.1%**
15/Mar/26	161,459	1,360	2,519	165,338	97,558	4,615	32,967	8,619	7,417	40,383	23,392	**24.0%**	23,392	**24.0%**
22/Mar/26	161,459	1,360	2,512	165,331	94,667	4,621	34,174	8,619	7,316	41,490	25,177	**26.6%**	25,177	**26.6%**
29/Mar/26	161,739	1,360	2,499	165,598	90,089	4,623	39,425	8,885	7,630	47,055	24,192	**26.9%**	24,102	**26.8%**

Key

Highlighted week beginning 18-Jan-26 denotes the minimum forecasted NPCC "Revised Net Margin".

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand and minimum Revised Net Margin.

Highlighted week beginning 22-Mar-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 September 26, 2025

Control Area Load and Capacity

	2	5	6	7	8	11	13	14	16	17	19	20
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 %
30/Nov/25	8,038	31	0	8,069	5,082	6,340	280	2,373	628	329	-63	-1.2%
7/Dec/25	8,038	31	0	8,069	5,164	6,340	265	1,603	934	329	305	5.9%
14/Dec/25	8,038	31	0	8,069	5,493	6,340	263	1,603	934	329	-27	-0.5%
21/Dec/25	8,038	31	0	8,069	5,548	6,340	264	1,525	934	329	-3	-0.1%
28/Dec/25	8,038	31	0	8,069	5,826	6,340	246	1,265	934	329	-39	-0.7%
4/Jan/26	8,137	31	0	8,168	5,974	6,340	259	1,354	934	329	-163	-2.7%
11/Jan/26	8,137	31	0	8,168	5,790	6,340	261	1,354	934	329	22	0.4%
18/Jan/26	8,137	31	0	8,168	6,066	6,340	260	1,354	934	329	-254	-4.2%
25/Jan/26	8,137	31	0	8,168	6,114	6,340	254	1,354	934	329	-309	-5.1%
1/Feb/26	8,137	31	0	8,168	6,074	6,340	259	1,346	934	329	-256	-4.2%
8/Feb/26	8,137	31	0	8,168	5,650	6,340	263	1,346	934	329	172	3.0%
15/Feb/26	**8,137**	**31**	**0**	**8,168**	**5,608**	**6,340**	**261**	**1,346**	**934**	329	212	3.8%
22/Feb/26	8,137	31	0	8,168	5,747	6,340	256	1,346	934	329	68	1.2%
1/Mar/26	8,137	31	0	8,168	5,369	6,340	256	1,341	934	329	451	8.4%
8/Mar/26	8,137	31	0	8,168	4,917	6,340	256	1,436	934	329	808	16.4%
15/Mar/26	8,137	31	0	8,168	4,606	6,340	252	1,773	934	329	778	16.9%
22/Mar/26	8,137	31	0	8,168	4,685	6,340	258	1,921	934	329	557	11.9%
29/Mar/26	8,137	31	0	8,168	4,278	6,340	260	1,797	934	329	1,090	25.5%

Key

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 22-Mar-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Winter 2025-26 Peak Load for Maritimes.

Notes

(1) Known Maint./Derate include wind.
(2) Week beginning 25-Jan-26 denotes the forecasted Maritimes Winter 2025-2026 Peak Week.

Table AP-3 – New England

Area ISO-NE
Revision Date October 14, 2025

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 %
30/Nov/25	29,367	935	440	30,742	19,063	22,818	0	2,689	2,125	3395	3,470	18.2%
7/Dec/25	29,367	935	440	30,742	19,324	22,818	0	1,476	2,125	4413	3,404	17.6%
14/Dec/25	29,367	935	440	30,742	19,334	22,818	0	819	2,125	5726	2,738	14.2%
21/Dec/25	29,367	935	440	30,742	19,390	22,818	0	806	2,125	6123	2,298	11.9%
28/Dec/25	29,367	935	440	30,742	19,390	22,818	0	806	2,125	6736	1,685	8.7%
4/Jan/26	29,367	935	440	30,742	19,637	22,818	0	784	2,125	6405	1,791	9.1%
11/Jan/26	29,367	935	440	30,742	20,056	22,818	0	804	2,125	6252	1,505	7.5%
18/Jan/26	29,367	935	440	30,742	20,056	22,818	0	878	2,125	5779	1,904	9.5%
25/Jan/26	29,367	935	440	30,742	20,056	22,818	0	793	2,125	5476	2,292	11.4%
1/Feb/26	29,367	935	440	30,742	19,855	22,818	0	767	2,125	5427	2,568	12.9%
8/Feb/26	29,367	935	440	30,742	19,615	22,818	0	783	2,125	5118	3,101	15.8%
15/Feb/26	29,367	935	440	30,742	19,589	22,818	0	783	2,125	4657	3,588	18.3%
22/Feb/26	29,367	935	440	30,742	19,352	22,818	0	804	2,125	4348	4,113	21.3%
1/Mar/26	29,367	935	440	30,742	18,461	22,818	0	1,301	2,125	2074	6,781	36.7%
8/Mar/26	29,367	935	440	30,742	18,147	22,818	0	1,580	2,125	2053	6,837	37.7%
15/Mar/26	29,367	935	440	30,742	17,970	22,818	0	1,724	2,125	2043	6,880	38.3%
22/Mar/26	29,367	935	440	30,742	17,641	22,818	0	1,807	2,125	2037	7,132	40.4%
29/Mar/26	29,367	935	440	30,742	17,132	22,818	0	2,269	2,125	2458	6,758	39.4%

Key

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 22-Mar-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted numbers denote forecasted Winter 2025-26 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.
Load forecast assumes net Peak Load Exposure (PLE) of 20,056 MW based on the 2025 CELT Report.
(4) On peak, 440 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) 2,125 MW operating reserve assumes 120% of the largest contingency of 1,250 MW and 50% of the second largest contingency of 1,250 MW.
(7) Assumed unplanned outages is based on historical observation of forced outages and any additional reductions for generation at risk due to natural gas supply.

This is not an energy analysis. A limited fuel supply with invalidate these numbers (for 50/50, 90/10 & Above 90/10)
500 MW addition for cold weather outages only added for Above 90/10 weeks with 21,948 MW load @ Dry Bulb Temp = -0.547

Table AP-4 – New York

Area NYISO
Revision Date October 14, 2025

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 %
30/Nov/25	40,062	1,203	1026	42,291	21,410	25,738	1	6,421	2,620	2,234	9,607	44.9%
7/Dec/25	40,062	1,203	1026	42,291	24,157	25,738	1	5,591	2,620	2,290	7,634	31.6%
14/Dec/25	40,062	1,203	1026	42,291	24,200	25,738	1	4,940	2,620	2,333	8,199	33.9%
21/Dec/25	40,062	1,203	1026	42,291	24,200	25,738	1	5,003	2,620	2,329	8,140	33.6%
28/Dec/25	40,080	1,203	1026	42,309	24,200	25,738	1	3,654	2,620	2,419	9,417	38.9%
4/Jan/26	40,080	1,203	1026	42,309	24,200	25,738	1	3,550	2,620	2,426	9,514	39.3%
11/Jan/26	40,080	1,203	1026	42,309	24,200	25,738	1	3,550	2,620	2,426	9,514	39.3%
18/Jan/26	40,080	1,203	1026	42,309	24,200	25,738	1	3,550	2,620	2,426	9,514	39.3%
25/Jan/26	40,080	1,203	1026	42,309	24,200	25,738	1	3,550	2,620	2,426	9,514	39.3%
1/Feb/26	40,093	1,203	1026	42,322	24,200	25,738	1	3,499	2,620	2,431	9,573	39.6%
8/Feb/26	40,093	1,203	1026	42,322	24,200	25,738	1	3,486	2,620	2,431	9,586	39.6%
15/Feb/26	40,093	1,203	1026	42,322	24,200	25,738	1	3,407	2,620	2,437	9,659	39.9%
22/Feb/26	40,093	1,203	1026	42,322	24,024	25,738	1	3,358	2,620	2,440	9,881	41.1%
1/Mar/26	40,113	1,203	1026	42,342	24,144	25,738	1	3,378	2,620	2,440	9,761	40.4%
8/Mar/26	40,113	1,203	1026	42,342	24,200	25,738	1	5,189	2,620	2,320	8,014	33.1%
15/Mar/26	40,113	1,203	1026	42,342	22,358	25,738	1	6,322	2,620	2,244	8,799	39.4%
22/Mar/26	40,113	1,203	1026	42,342	21,879	25,738	1	6,937	2,620	2,204	8,703	39.8%
29/Mar/26	40,393	1,203	1026	42,622	21,502	25,738	1	7,996	2,620	2,152	8,353	38.8%

Key

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 22-Mar-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Winter 2025-26 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 September 19, 2025

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 %
30/Nov/25	37,840	-420	818	38,237	20,894	24,979	0	12,214	1,567	1,124	2,438	**11.7%**
7/Dec/25	37,908	-420	818	38,306	20,794	24,979	0	11,907	1,567	1,084	2,953	**14.2%**
14/Dec/25	37,908	-420	818	38,306	21,015	24,979	0	11,017	1,567	1,238	3,469	**16.5%**
21/Dec/25	37,908	-420	818	38,306	20,389	24,979	0	10,555	1,567	1,174	4,620	**22.7%**
28/Dec/25	37,958	-420	818	38,356	21,181	24,979	0	10,259	1,567	1,062	4,287	**20.2%**
4/Jan/26	37,958	-420	818	38,356	22,004	24,979	0	9,796	1,567	1,156	3,832	**17.4%**
11/Jan/26	37,958	-420	818	38,356	21,944	24,979	0	9,851	1,567	1,186	3,808	**17.4%**
18/Jan/26	37,958	-420	868	38,406	22,042	24,979	0	10,345	1,567	1,148	3,304	**15.0%**
25/Jan/26	37,958	-420	818	38,356	21,991	24,979	0	10,563	1,401	1,137	3,263	**14.8%**
1/Feb/26	37,958	-420	818	38,356	21,336	24,979	0	10,778	1,401	1,382	3,459	**16.2%**
8/Feb/26	**37,958**	**-420**	**818**	**38,356**	**21,284**	24,979	**0**	**10,566**	**1,401**	**1,554**	**3,551**	**16.7%**
15/Feb/26	37,958	-420	868	38,406	21,001	24,979	0	10,603	1,401	1,471	3,929	**18.7%**
22/Feb/26	37,958	-420	818	38,356	20,944	24,979	0	10,526	1,401	1,403	4,082	**19.5%**
1/Mar/26	37,958	-420	818	38,356	20,351	24,979	0	11,427	1,401	1,250	3,926	**19.3%**
8/Mar/26	37,958	-420	818	38,356	19,836	24,979	0	11,549	1,401	1,251	4,319	**21.8%**
15/Mar/26	37,958	-420	818	38,356	19,399	24,979	0	12,201	1,401	1,301	4,054	**20.9%**
22/Mar/26	37,958	-420	818	38,356	18,930	24,979	0	12,046	1,401	1,246	4,733	**25.0%**
29/Mar/26	37,958	-420	818	38,356	18,525	24,979	0	13,088	1,667	1,191	3,885	**21.0%**

Key

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 22-Mar-26 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Winter 2025-26 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) The winter peak for electricity demand set on December 20, 2004 was 24,979 MW.
(6) Purchase Contract applies only to EEA1 and above

Table AP-6 – Québec

Area	Québec
Revision Date	October 14, 2025

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	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
30/Nov/25	45,884	-389	235	45,730	33,386	42,790	4,362	6,624	1,539	1,500	6,443	19.3%
7/Dec/25	45,884	-389	243	45,738	35,256	42,790	4,362	6,307	1,539	1,500	4,898	13.9%
14/Dec/25	45,884	-389	248	45,743	36,477	42,790	4,362	6,236	1,539	1,500	3,753	10.3%
21/Dec/25	45,884	-389	248	45,743	36,362	42,790	4,362	6,096	1,539	1,500	4,008	11.0%
28/Dec/25	45,884	-389	251	45,746	37,194	42,790	4,362	5,762	1,539	1,500	3,513	9.4%
4/Jan/26	45,884	-389	258	45,753	38,806	42,790	4,362	5,627	1,539	1,500	2,043	5.3%
11/Jan/26	45,884	-389	264	45,759	40,215	42,790	4,362	5,487	1,539	1,500	780	1.9%
18/Jan/26	45,884	-389	265	45,760	40,446	42,790	4,362	5,594	1,539	1,500	443	1.1%
25/Jan/26	45,884	-389	263	45,758	39,903	42,790	4,362	5,914	1,539	1,500	664	1.7%
1/Feb/26	45,884	-389	257	45,752	38,530	42,790	4,362	5,926	1,539	1,500	2,019	5.2%
8/Feb/26	45,884	-389	255	45,750	38,029	42,790	4,362	5,955	1,539	1,500	2,489	6.5%
15/Feb/26	45,884	-389	250	45,745	36,971	42,790	4,362	6,081	1,539	1,500	3,416	9.2%
22/Feb/26	45,884	-389	248	45,743	36,317	42,790	4,362	6,283	1,539	1,500	3,866	10.6%
1/Mar/26	45,884	-389	245	45,740	35,617	42,790	4,362	8,671	1,539	1,500	2,175	6.1%
8/Mar/26	45,884	-389	241	45,736	34,740	42,790	4,362	9,784	1,539	1,500	1,935	5.6%
15/Mar/26	45,884	-389	235	45,730	33,226	42,790	4,362	10,947	1,539	1,500	2,280	6.9%
22/Mar/26	45,884	-389	228	45,723	31,532	42,790	4,362	11,463	1,539	1,500	3,451	10.9%
29/Mar/26	45,884	-389	215	45,710	28,651	42,790	4,362	14,275	1,539	1,500	3,507	12.2%

Key

Highlighted week beginning 18-Jan-26 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 22-Mar-26 denotes week with the largest forecasted NPCC "Revised Net Margin".

Highlighted number denotes forecasted Winter 2025-26 Load for Québec area.

Notes

(1) Includes Independant Power Producers (IPPs) and available capacity of Churchill Falls at the Newfoundland - Québec border.
(2) Includes firm sale of 145 MW to Cornwall and transmission losses due to firm sales.
(3) Includes 64% of Wind capacity derating.
(4) Numbers published in this report may not exactly correspond to the values available on other Hydro-Québec public information sources because assumptions specific to the current report are applied.
(5) Purchase Contract applies only to EEA1 and above

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 account for the capacity values for derated renewable resources.

New York

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

Ontario

This number includes all generation registered with the IESO.

Québec

Most of the Installed Capacity in the Québec Area is owned and operated by Hydro-Québec. 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.

Known Maintenance/Derates

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 and 50% of the second-largest contingency.

New England

The operating reserve requirement consists of 120% of the first largest contingency and 50% of the second largest contingency.

New York

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

Ontario

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

Québec

The operating reserve requirement consists of 100% of the largest first contingency and 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. The Unplanned Outages for 90/10 and Above 90/10 load forecasts include an additional 500 MW derate to account for resources that, “fail-to-start”, due to extreme cold weather.

New York

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

Ontario

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

Québec

This value is a provision for winter forced outages that are reviewed annually against historical data.

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.

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

Revised Net Margin (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 Winter Transfer Capabilities

The following table represents the forecasted transfer capabilities between Reliability Coordinator Areas represented as Total Transfer Capability (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. This 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 services 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/
- **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			
Matapédia, Madawaska	773	773	Eel River winter rating is 350 MW (2 MW of losses). Madawaska HVDC winter rating is 425 MW.
Total	**773**	**773**	
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)	1,200	1,200	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.

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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	**1,730**	**1,730**	
Québec			
Phase II HVDC link (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 170 MW.

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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.
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)	1,800	1,600	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	**2,330**	**2,130**	
Ontario			
Lines PA301, PA302, BP76, PA27, L33P, L34P	1,850	1,550	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	**1,850**	**1,550**	
PJM			
PJM AC Ties	2,400	2,100	New York applies a 300 MW Transmission Reliability Margin (TRM).
NYC/PJM Linden VFT	315	315	
Total	**2,715**	**2,415**	
Québec			
Chateauguay (QC)/Massena (NY)	1,000	1,000	
Cedars / Québec	100	100	
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	2,100	1,900	The TRM is 200 MW.
Total	**2,100**	**1,900**	
MISO Michigan			
Lines L4D, L51D, J5D, B3N	1650	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	140	140	There is no capacity to export to Québec through Lines P33C and X2Y.

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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.
East / Beau 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.
Total	**2,165**	**2,115**	
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
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	**1200**	**1080**	Radial load transfer amount is dependent on local loading and is updated monthly and reviewed annually.
New England			
NIC / CMA HVDC link	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	1,250	1,250	
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).
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	2079	2079	
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.)	320	320	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	**2,865**	**2,865**	

Import Transfers from Regions External to NPCC

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Constraint
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	368	343	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	2,350	2,050	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	**3,985**	**3,685**	

Appendix IV – Demand Forecast Methodology

Reliability Coordinator Area Methodologies

Maritimes

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

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

For Nova Scotia, the load forecast is based on a 10-year weather average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

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

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

To determine Load Forecast Uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four-year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 5% 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[23] 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 long-term load forecast 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.[24]

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.[25]

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

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[23] 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.

[24] 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.

[25] 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.

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 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[26].

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

[26] See: ISO-NE Forecast and Scheduling, Reserve Adequacy Analysis.

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

The forecast of BTM solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

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.

The winter peak forecast is developed by NYISO using winter temperature which is representative of normal weather during peak demand conditions. The weather assumptions for most regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

There are two higher-than-expected scenarios forecast for the NYCA. One is a forecast based on 90/10 weather conditions, set to the 90th percentile of typical peak-producing weather conditions. The other is a forecast based on 99/1 weather conditions, set to the 99th percentile of peak-producing weather conditions. The 90th and 99th percentile peak forecasts are based on the historical variation in peak day weather coupled with projected temperature trends. The 90th percentile winter peak forecast represents a colder than expected winter peak day, while the 99th percentile winter peak forecast represents an extremely cold winter peak day with a well below expected temperature.

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/

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.hydroquebec.com

Appendix VII – References

For historical NPCC Reliability Assessments, please visit:

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

Appendix VIII – CP-8 2025-2026 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment for Winter 2025-2026

RCC Approved Dec. 1, 2025
Conducted by the NPCC CP-8 Working Group

Final Report - Public

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The CP-8 Working Group acknowledges the efforts of Alexis Gogola, Shannon Tucker, and Matt Etkins of GE Energy Consulting, Cary Oler of the Solar Terrestrial Dispatch, Andrey Oks and Michael Lombardi of the Northeast Power Coordinating Council, Inc., and thanks them for their assistance in this analysis.

TABLE OF CONTENTS

1. Executive Summary

This report, which was prepared by the CP-8 Working Group, estimates the use of the available NPCC Area Operating Procedures to mitigate resource shortages from November 2025 through March 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 consistent with the CO-12 Working Group's study, "NPCC *Reliability Assessment for Winter* 2025-2026", December 2025[27] and summarized in **Table 1**.

Area	50/50 Peak[28] (MW)	Higher Peak[29] (MW)	Available Capacity[30] (MW)	Peak Month
Québec (HQ)	40,736	44,036	46,071	January
Maritimes Area (MT)	6,033	6,588	7,812	January
New England (NE)	20,056[31]	20,970	30,036[32]	December
New York (NY)	24,200	25,742	39,699	January
Ontario (ON)	22,706	23,633	33,999	January

Table 1: Assumed Load and Base Case Capacity for Winter 2025-2026

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

[27] See: Seasonal Assessment.
[28] The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.
[29] The higher peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.
[30] 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.
[31] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 20,056 MW; BTM PV reduction = 0; Net peak = 20,056 MW.
[32] Total generation = 31,934 MW + Active DR (440 MW) + Net import (1,235 MW) - Gas at risk (3,583 MW) = 30,036 MW (Net).

seven percent chance of occurring. While the higher peak load level, as defined for this study, 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 **Table 9** 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 November 2025–March 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.[33]

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Higher Load Level				
External Assistance Calls	7.205	42.185	-	-	0.061	33.910	84.710	-	-	0.826
Activation of DR/SCR	0.721	-	-	-	-	6.947	-	-	-	-
Reduce 30-min Reserve	0.392	8.375	-	-	-	4.703	31.156	-	-	-
Initiate Interruptible Loads/Voltage Reduction[34]	0.003	5.654	-	-	-	0.040	22.526	-	-	-
Reduce 10-min Reserve[35]	0.001	1.453	-	-	-	0.020	7.779	-	-	-
Appeals	-	0.189	-	-	-	-	1.410	-	-	-
Disconnect Load	-	0.189	-	-	-	-	1.410	-	-	-

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

Under Base Case conditions, only the Maritimes and Québec Areas show a likelihood of using their operating procedures designed to mitigate resource shortages during the 2025-2026 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven load levels). For Québec, this is limited to activation of Demand Response

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

Program (DR). For Maritimes, this includes reducing 30-min and 10-min reserve and initiating interruptible loads. The results for the highest load levels forecast (based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring) also estimates a need Québec to reduce 30-min reserve and the Maritimes Area shows a notable likelihood of utilizing its Operating Procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.

Although demand and resource levels in the Maritimes are similar to last winter, elevated Loss of Load Expectation (LOLE) are a result of modeling assumptions. The current probabilistic model uses a narrower wind dataset (2020–2024), which lowers expected wind output during peak hours compared to last year's broader range. This is related to an effort to drive consistency between temporal wind output within NPCC Areas in reliability assessments. Additional planned maintenance outages and reduced support from neighboring regions further contribute to the risk. These results are also driven by the Maritimes' forecast load and corresponding reserve margin expectations. In addition, the results show the Maritimes, Québec and Ontario have varying reliance on external assistance during the winter 2025-2026 period. This assessment suggests that operators in the Maritimes will likely need to implement emergency operating procedures and/or Emergency Energy Alerts (EEAs) during periods of unusually high demand or reduced resource availability.

Table 3 shows the estimated use of demand response programs and operating procedures under the Severe Case assumptions for the expected (50/50) load level and the highest load level scenarios for the November 2025–March 2026 period. Occurrences greater than 0.5 days/period are highlighted.[36]

[36] Rounded to the nearest whole occurrence, likelihoods of greater than 0.5 days/period are highlighted.

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Higher Load Level				
External Assistance Calls	11.485	69.158	0.007	0.002	0.061	44.227	106.263	0.094	0.021	0.826
Activation of DR/SCR	1.943	-	-	-	-	13.271	-	-	0.005	0.003
Reduce 30-min Reserve	1.348	24.368	0.004	-	-	10.360	58.711	0.055	0.002	-
Initiate Interruptible Loads/Voltage Reduction[37]	0.026	18.214	0.001	-	-	0.394	50.031	0.017	0.001	-
Reduce 10-min Reserve[38]	0.015	6.139	-	-	-	0.223	24.153	0.010	-	-
Appeals	0.002	1.082	-	-	-	0.034	6.438	0.010	-	-
Disconnect Load	0.002	1.082	-	-	-	0.033	6.438	0.003	-	-

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

As shown in **Table 3**, Under Severe Case conditions, the Maritimes Area risks increases assuming reduced resource scenario, especially for the highest load levels forecast. For the highest load levels forecast (having approximately a 7% chance of occurring), the Maritimes Area shows an increased likelihood of using their operating procedures designed to mitigate shortages during the 2025-2026 winter period. These results are driven by the areas forecast of economic variations and weather uncertainties, and modeling assumptions. These modeling assumptions contributed to a greater dependence on emergency procedures during periods of extreme peak demand or limited resource availability. While no transmission infrastructure issues are anticipated this season, and the Maritimes Area has not identified any operational concerns expected to affect system reliability, emergency operations and planning protocols remain in place should an event arise.

[37] Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
[38] New York initiates Appeals prior to reducing 10-min Reserve.

2. Introduction

This report was prepared by the CP-8 Working Group and estimates the use of NPCC Area Operating Procedures designed to mitigate resource shortages from November 2025 through March 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 study, *NPCC Reliability Assessment for Winter* – 2025-2026, December 2025. The CP-8 Working Group's Objective, Scope of Work, and Schedule are shown in **Appendix A**.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program was used for the analysis and GE Energy was retained by NPCC to conduct the simulations. **Appendix E** provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 5.7.3765 was used for this assessment.

3. Study Assumptions

The database developed by the CP-8 Working Group for the NPCC *Reliability Assessment for Summer 2025 and the 2025 NPCC Long Range Adequacy Overview*[39] was used as the starting point for this analysis. Working Group members reviewed the existing data and revised reflect the conditions expected for the winter 2025-2026 assessment period.

3.1 Demand

3.1.1 Load Assumptions

Each area provided annual or monthly peak and energy forecasts for winter 2025-2026. **Table 4** summarizes each Area's winter 50/50 peak load assumptions for the study period.

Area	Month	Peak Load (MW)
Québec	January	40,736
Maritimes Area	January	6,033[40]
New England	December	20,056[41]
New York	January	24,200
Ontario	January	22,706

Table 4: Assumed NPCC Areas 2025-2026 50/50 Winter 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.

[39] See: Reliability Services | NPCC.
[40] Maritimes Area's CO-12 WG peak load is different than the CP-8 WG forecast, due to not including the impact of the demand response in the deterministic seasonal assessment since currently demand response programs are not dispatchable.
[41] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 21,056 MW; BTM PV reduction = 0; Net peak = 20,056 MW.

New England

ISO New England's long-term energy model and seasonal forecast have undergone methodology updates for CELT 2025. The changes are described in the 2025 Final Draft Energy and Seasonal Peak Forecasts presentation. The peak demand forecast for the region and the eight load zones is a coincident peak demand forecast with both gross and net values reported within ISO-NE's 2025 Forecast Report of Capacity, Energy, Loads, and Transmission (the 2025 CELT Report). The gross reference (50/50) winter peak forecast is 20,056 MW for the winter of 2025-2026. ISO-NE's long-term forecast 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.

In addition to the annual update to ISO-New England's forecast for both peak demand and energy, ISO-New England also forecasts the anticipated growth and impact of behind-the-meter photovoltaic (BTM PV) resources within the Balancing Authority area that do not participate in wholesale markets. ISO-New England's BTM PV forecast is developed annually with stakeholder input from the Distributed Generation Forecast Working Group. For the BTM PV forecast, the resources are considered to be those with typically 5 MW or less in nameplate capacity that are interconnected to the distribution system according to state-jurisdictional interconnection standards. The 2025 BTM PV forecast can be found using the following link: ISO-NE Final 2025 Photovoltaic (PV) Forecast.

Around 8,315 MW (AC nameplate rating) of installed PV resources are expected within New England by the end of 2025; most of them (~5,002 MW nameplate rating) are BTM PV resources. Their contribution to reducing system peaks, however, is diminished during the winter period, because New England's daily forecasted winter peak typically occurs during the evening hours, when the PV contribution is significantly reduced.

The 2025 load forecast does not include a separate Energy Efficiency (EE) component. The EE forecast is integrated into the base load.

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.[42]

Ontario

The Ontario IESO demand forecast for the CP-8 Working Group probabilistic assessment is consistent with the Ontario IESO Reliability Outlook[43] published on September 18, 2025.

Québec

The load forecast is consistent with the assumptions used in Hydro-Québec's 2025 Annual Supply Plan update on November 1, 2025. The energy-sales forecast is built on the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and

[42] See: 2025 Gold Book (nyiso.com).
[43] Additional information describing Ontario's demand forecasting may be found at: http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook.

different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use/sector peak demands is the total monthly peak demand.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on more than 50 years of temperature history, adjusted by +0.3 °C (+0.5 °F) per decade starting in 1971 to account for climate change. Moreover, each year of historical weather data is shifted up to ±9 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of more than 300 different demand scenarios. 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.

3.1.2 Load Model in MARS

In previous assessments, the CP-8 Working Group used the historical load shape based on the 2013-2014 winter. The selection of the winter hourly load assumption is revaluated on an annual basis with the previous winter load shape.[44] The CP-8 Working Group compared the results of this assessment using the 2024-2025 and 2013-2014 load shapes and found the 2013-2014 load shape to be more stressful on a region-wide basis Therefore, the most conservative load shape for the probabilistic assessment may not necessarily be from the season with the most severe weather was observed.

The loads for each Area were modeled on an hourly, chronological basis, using the 2013-2014 hourly load shape. The MARS program modified the hourly loads through time to meet each Area's winter peak demand and energy forecasts. **Figure 1** shows the diversity in the NPCC area monthly 50/50 peak load shapes used in this analysis, with the 2013-2014 load shape assumptions.

[44] See: Analysis of the 2024/25 Winter Load Shape (npcc.org).

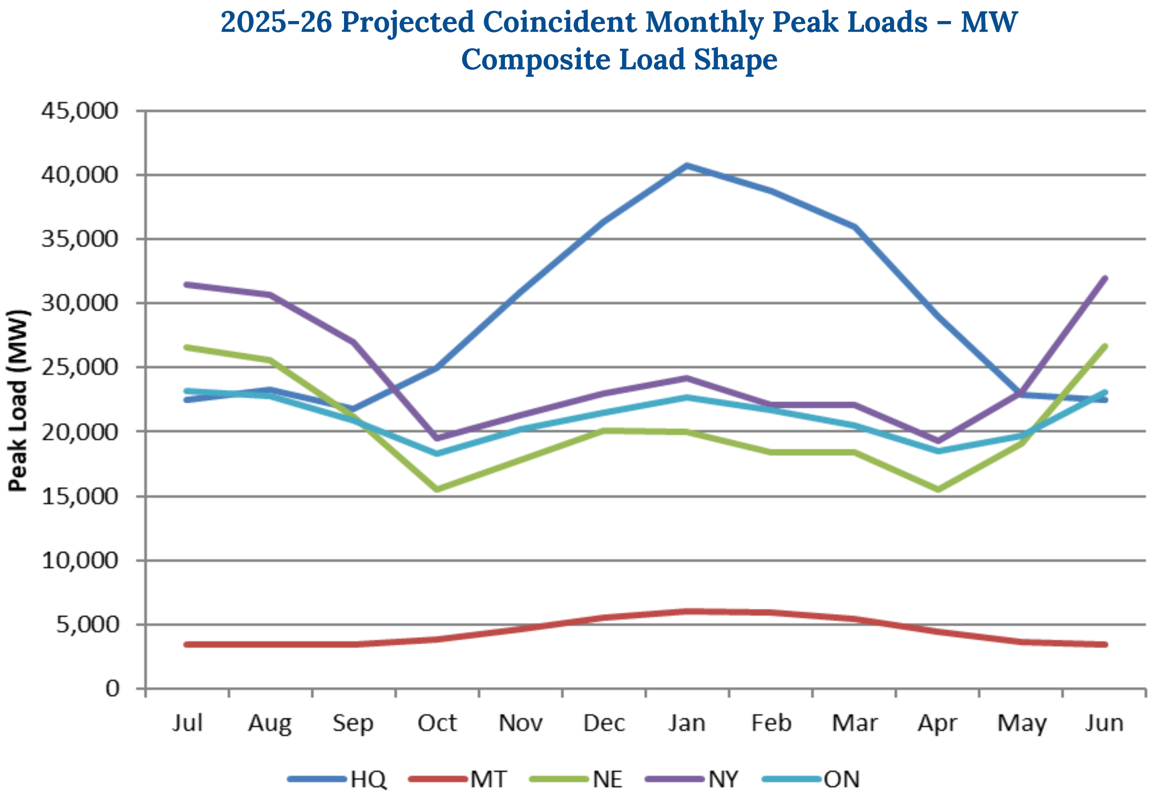

Figure 1: 2025-2026 Projected Monthly Peak Loads for NPCC

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 in MARS. The program computes the reliability indices at each of the specified load levels and calculates weighted-average values based on input probabilities of occurrence. For this study, seven load levels were modeled based on the monthly load forecast uncertainty provided by each Area. For example, if the 50/50 Load December 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*1.042.[45]

The seven load levels represent the expected load level and one, two and three standard deviations above and below the expected load level.

In computing the reliability indices, all the Areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty

[45] As highlighted on **Table 5**. Probability weighted average of the top two load variations (1.057*{0.0062/ (0.0062+0.0606)} +1.041*{0.0606/ (0.0062+0.0606)} = 1.042).

affect all the Areas at the same time. The amount of the effect can vary according to the variations in the load levels.

Table 5 shows the load variation assumed for each of the seven load levels modeled and the probability of occurrence for the winter 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.

Area	Per-Unit Variation in Load						
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 7
HQ	1.116	1.081	1.033	0.984	0.932	0.877	0.846
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.124	1.046	0.997	0.939	0.913	0.685	0.389
NY	1.104	1.064	1.028	0.994	0.963	0.933	0.904
ON	1.057	1.041	1.021	1.000	0.976	0.948	0.920
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 the month of January 2026

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.

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**.

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 in NPCC.

3.2 Resources

Table 6 below summarizes the winter 2025-2026 capacity assumptions for the NPCC Areas used in the analysis for the Base Case Scenario and are consistent with the assumptions used in the NPCC CO-12 Working Group, NPCC *Reliability Assessment for Winter* 2025-2026, December 2025.

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

	HQ	MT	NE	NY	ON
Assumed Capacity[46]	46,071	7,812	30,036	39,699	33,999
Demand Response[47]	0	259	625	1,487	868
Net Imports/Exports[48]	-553	-122	567	679	-420
Reserve (%)	11.7	31.8	65.8	73.0	51.7
Scheduled Maintenance[49]	-	146	618	0	0

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

Details regarding the NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent NPCC Review of Resource Adequacy.[50] 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:

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 2025-2026 winter, and their ratings are based on their Seasonal Claimed Capability. Settlement Only Generating (SOG) resources are not included in this assessment, but they do participate in the energy market and help serve New England system loads.

Wind and solar generation

Hourly output profiles are used to model solar and wind resources. The total Network Resource Capability (NRC) of solar resources is calculated by aggregating them by zone and

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[46] Assumed Capacity - the total generation capacity assumed to be installed at the time of the winter peak. For New England, this is the amount of generation capacity assumed available after reflecting the reduction from gas-fired generation assumed due to fuel supply (3,583 MW).
[47] 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.
[48] Net Imports / Exports: the amount of expected firm imports and exports at the time of the winter peak. The value is positive for imports and negative for exports.
[49] Maintenance scheduled at time of peak.
[50] See: NPCC Area's Review of Resource Adequacy.

modeling their hourly output profiles for five historical years (2020–2024) based on their simulated output over the previous five years. With every sample draw, GE MARS chooses at random one of the five profiles. Five years' worth of hourly production profiles are used to model wind resources. In GE MARS, every sample draw corresponds to a randomly selected profile.

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 resources assumed in this assessment also include the Active Demand Capacity Resources and capacity imports from the neighboring areas. These demand resources and firm imports are based on their Capacity Supply Obligations associated with the 1st Annual Reconfiguration Auction for Capacity Commitment Period (CCP) of 2025-2026.[51]

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 2025–2026 Capability Year*, dated January 21, 2025,[52] and the *New York Control Area Installed Capacity Requirement for the Period May* 2025-*April* 2026 New York State Reliability Council, December 06, 2024, report.[53]

Ontario

Generating unit availability was based on the Ontario IESO *Reliability Outlook - An Adequacy Assessment of Ontario's Electricity System from October 2025 to March 2027*, dated September 18, 2025.[54]

Québec

The planned resources are consistent with the *NERC 2025-2026 Winter Reliability Assessment*.[55] The planned outages for the winter period are reflected in this assessment in the available capacity. The number of planned outages is consistent with historical values.

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[51] The 2025-2026 CCP starts on June 1, 2025, and ends on May 31, 2026.
[52] See: https://www.nyiso.com/documents/20142/49410485/2025-2026-LCR-Report-Clean.pdf.
[53] See: https://www.nysrc.org/wp-content/uploads/2024/12/2025-IRM-Study-Technical-Report_Final_12062024_clean.pdf.
[54] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2025Sep.pdf.
[55] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The MARS modelling details for each type of resource in each Area are provided in **Appendix D** of the report.

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 winter 2025-2026 period.

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 345 kV, 230 kV, and 115 kV transmission lines, which in northern New England generally are longer and fewer in number than in southern New England. The region has 13 interconnections with neighboring power systems in the United States and Eastern Canada. Nine interconnections are with New York (NYISO) (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 converter station, which converts alternating current to direct current and then back to alternating current. The other is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (i.e., Phase II).

The New England Clean Energy Connect (NECEC), a new 1,200 MW, tie line connecting Québec to Lewiston, Maine will be commercialized (in late 2025). An energy-only contract into Maine/New England has been signed. Energy-only contracts are not modeled in this study.

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.

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 with 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 Stanstead feeding Citizen's Utilities in New England. Moreover, in addition to the Châteauguay HVDC back-to-back interconnection to New York, radial generation can be 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 to be switched on either system.

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[56], New York[57], and New England[58] are provided in the respective references.

[56] See: http://www.ieso.ca/localContent/ontarioenergymap/index.html.
[57] See: https://www.nysrc.org/wp-content/uploads/2023/12/2024-25-IRM-Resolution-12-8-2023-final.pdf.
[58] The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/index.html.

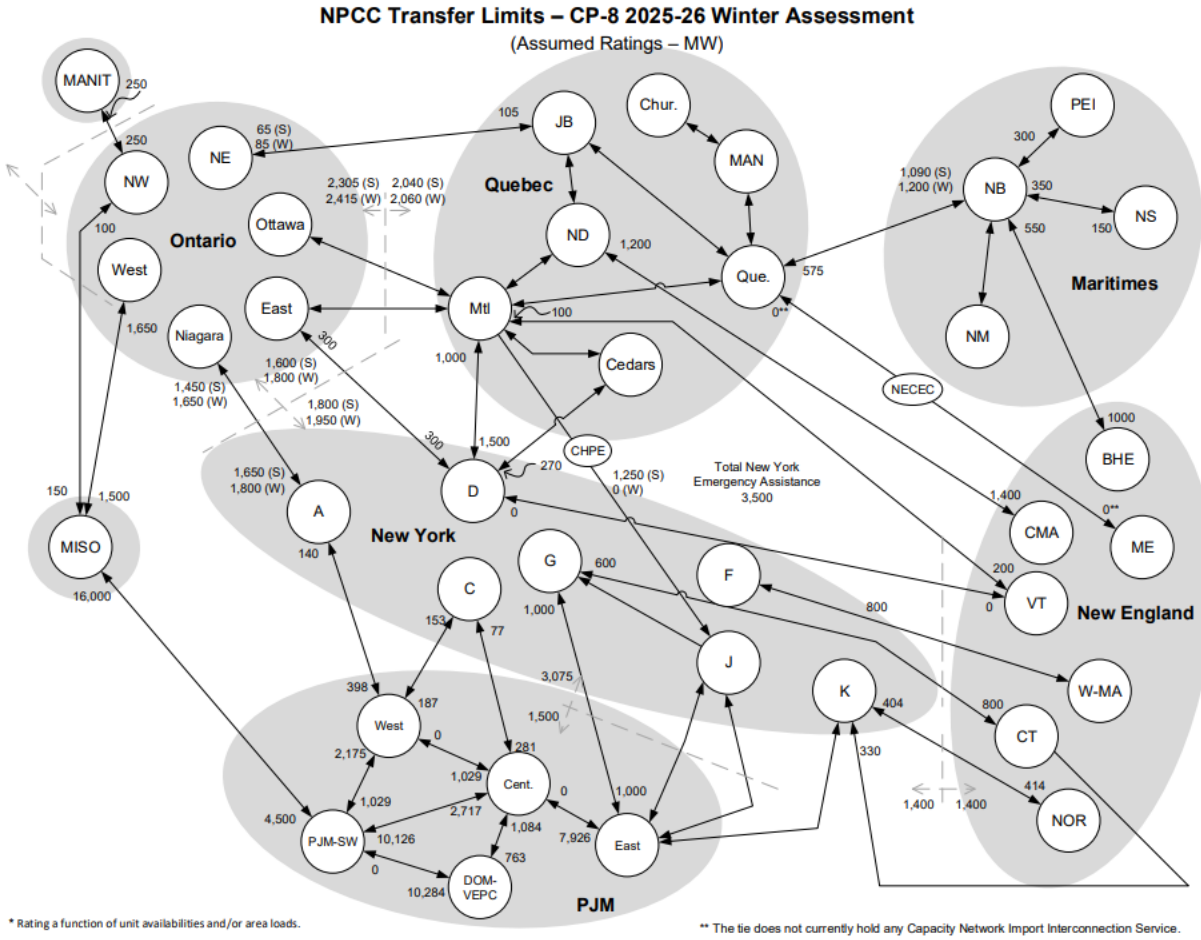

Figure 2: Assumed Transfer Limits

Note: *With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro-Québec can import up to 100 MW from New York.*[59]

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				

[59] See: http://www.oasis.oati.com/HQT/.

3.4 Operating Procedures to Mitigate Resource Shortages

Each Area takes defined steps as their reserve levels approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting 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 [60]	ON
1. Curtail Load Public Appeals RT-DR / SCR SCR Load / Man. Volt. Red.	- - 4,201 -	- - - -	- - - -	- - 0 0.2 %	- 1% - -
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction Interruptible Load [61]	250 -	- 259	205 -	1.3% 261	0% 868
4. No 10-min Reserves Appeals / Curtailments	750 -	505 -	- -	- 74	945 -
5. 5% Voltage Reduction No 10-min Reserves Appeals / Curtailments	- - -	- - -	- 800 -	- 910 -	1.85% - -

Table 7: NPCC Operating Procedures – 2025-2026 Winter Load Relief Assumptions (MW)

The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in **Table 7** was a reasonable approximation for this analysis.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure,

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

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**.

	PJM	MISO
Peak Load (MW)	142,800	74,434
Peak Month	January	January
Assumed Capacity (MW)	186,048	102,915
Purchase/Sale (MW)	-1,808	978
Reserve (%)	33.0	47.3
Weighted Unit Availability (%)	89.5	83.7
Operating Reserves (MW)	3,655	3,906
Curtailable Load (MW)	5,616	5,754
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 +/- 14.3, 9.6, 4.8	100.0 +/- 12.0, 8.0, 4.0

Table 8: PJM and MISO 2025-2026 Base Case Assumptions[62]

[62] 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 winter 2025-2026 Projected Monthly 50/50 Peak Loads for NPCC, PJM and MISO for the 2013-2014 Load Shape assumption.

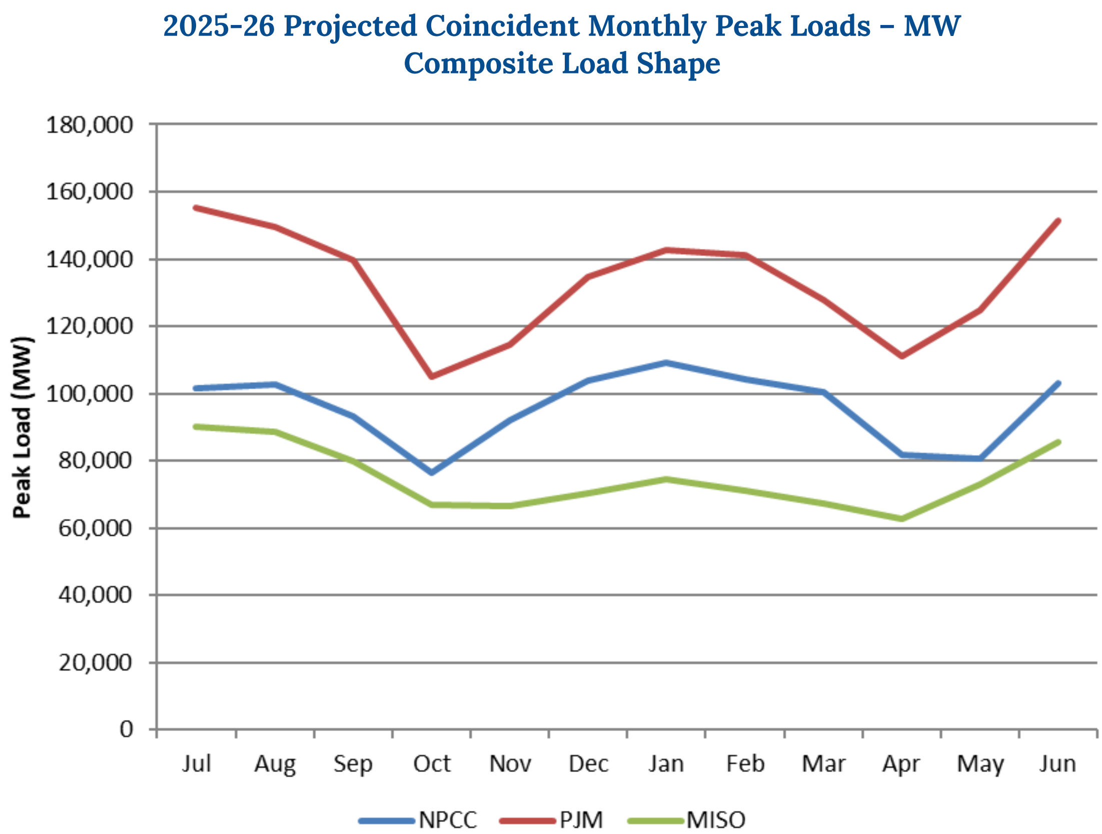

Figure 3: 2025-2026 Projected Monthly Winter Peak Loads – 2013-2014 Load Shape

Beginning with the 2015 NPCC *Long Range Adequacy Overview*, (LRAO)[63] 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.

[63] See: https://www.npcc.org/reliability-services?category=Resource%20Adequacy.

3.6.1 PJM-RTO

Load Model

The load model used for the PJM-RTO in this study is consistent with the PJM Planning division's technical methods.[64] The hourly load shape is based on observed 2013-2014 calendar year values, which reflects representative weather and economic conditions for a winter peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2025.[65] Load Forecast Uncertainty was modeled consistent with recent planning PJM models[66] 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.[67]

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[64] 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.
[65] See: https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.
[66] See: https://www.pjm.com/-/media/planning/res-adeq/2023-pjm-reserve-requirement-study.ashx.
[67] See: https://www.pjm.com/planning.aspx.

3.7 Study Scenarios

The study evaluated three Cases; summary descriptions are provided in **Tables 9** and **10**.

	Base Case Assumptions	Severe Case – Additional Constraints
System	- As-Is System for the 2025-2026 period - Transfers allowed between Areas - 2013-2014 Load Shapes adjusted to the Area's year 2025 forecast (expected & extreme assumptions)	- Transfer capability between NPCC and MRO/RFC- 'Other' reduced by 50%.
Maritimes	- The Capacity and Load [68] align with the forecast assumptions outlined in the 2025 NERC *Winter Reliability Assessment* [69] - ~1,153 MW of installed wind generation (modeled using calendar year 2024 hourly wind year) - 122 MW external export contracts assumed - 248 MW of demand response (interruptible load) available in the Maritimes during the winter period	- Wind capacity is de-rated by half (1,153 MW to 576.5 MW) for every hour in December, January and February to simulate icing conditions - 50% natural gas capacity curtailment (594 to 297 MW) assumed for winter 2025-2026 to simulate a reduction in gas supply for December, January, and February (assuming dual fuel units revert to oil)[70]
New England	- Existing and planned generation resources and load forecast (BTM PV forecast) for the Winter 2025-2026 consistent with the 2025 ISO-NE *Capacity, Energy, Loads, and Transmission (CELT) Report* [71] - Active Demand for Capacity Resources and Imports based on 2025-2026 Capacity Commitment Period 2nd Annual Reconfiguration Auction (ARA2) held in 2025	- Assume 50% reduction to the import capabilities of external ties - 500 MW of additional planned maintenance schedule - 4,513 MW of gas-fired generation at risk due to fuel supply under severe conditions assumed unavailable

[68] Note: These 2025-2026 Winter Reliability assessment assumptions were based on the 2025 NERC Long Term Reliability Assessment data for Winter 2025-2026. Wind: NB: 349 MW, NS:1253 MW, PEI: 200.6 MW, NM: 42 MW.
[69] 2025-2026 NERC Winter Reliability Assessment Report.
[70] A total of (2* 49 MW) 98 MW GV, 290 MW Bayside, (49 MW+49 MW +46 MW) 222 MW for Tufts Cove 1, 4,5, and 6 - pure natural gas units (not dual fueled), all divided by 2 for severe assumptions.
[71] See: CELT Reports (iso-ne.com).

	Base Case Assumptions	Severe Case – Additional Constraints
	- Hourly output profiles for wind and solar generation for five historical years - Behind the Meter Photovoltaic (BTM PV)[72] is modeled as a load modifier on an hourly basis that corresponds to the NPCC load shape year - Planned maintenance schedules[73] - 3,853 MW gas-fired generation at risk due to fuel supply under expected condition assumed unavailable[74]	
New York	- Updated Load Forecast - (NYCA Winter 2025-2026 peak load forecast - 24,200 MW; NYC 7,580 MW; LI – 3,265 MW) - Assumptions consistent with New York Installed Capacity Requirements for May 2025 through April 2026[75] - Actual hourly plant profiles used for wind and solar generation over the period 2019-2023[76]	- Extended Maintenance in southeastern New York (500 MW) - 600 MW of assumed Cable transmission reduction across HVDC facilities - 5,000 MW of generation assumed unavailable across fleet due to fuel delivery issues.
Ontario	- Forecast consistent with Ontario IESO's Reliability Outlook – An Adequacy Assessment of Ontario's Electricity System - October 2025 to March 2027[77] - Planned supply and Firm demand with Expected Weather. Planned Supply refers to all firm supply contracted resources expected to come online during the upcoming season	- ~800 MW of maintenance extended into the winter period

[72] 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.
[73] Provided list of planned maintenance outages occurring during the study window (11/1/2025 to 5/31/2026).
[74] The gas at risk assumptions is sourced from column 7 of the AMS Operable Capacity Analysis published on Aug 1, 2025.
[75] Offshore wind uses normalized offshore wind shapes as published by NYISO over the period 2017-2021 and for land-based wind shape new units will use zonal hourly averaged or nearby units.
[76] NYISO identified generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as the temporary solution for the reliability need in New York City these generators will remain available for two years beyond the May 1, 2025, deactivation date established by the Peaker Rule.
[77] See: Reliability Outlook (ieso.ca).

	Base Case Assumptions	Severe Case – Additional Constraints
Québec	- Resources and the load forecast are consistent with data submitted for the 2025 NERC Winter Reliability Assessment - including about 1,500 MW of scheduled maintenance and restrictions - 4,024 MW of installed wind capacity modeled using historical data from 2020-2024 - 4,900 MW of demand response - 600 MW of firm capacity imports - 845 MW of firm capacity exports	- 1,000 MW of capacity assumed to be unavailable for the winter peak period

Table 9: Base and Severe Case Assumptions for NPCC Areas

	Base Case Assumptions	Severe Case Assumptions
PJM-RTO	- As-Is System for the 2025-2026 winter period - Load Shapes adjusted to the 2025 forecast provided by PJM - Load forecast uncertainty based on PJM reference - Operating Reserve 3,655 MW (30-min. 1,218 MW; 10-min. 2,437 MW)	- Gas-fired only capacity not having firm pipeline transportation, assumed ~6,400 MW unavailable - One percentage point increase in load forecast uncertainty - Ice Storm; ice blocking fuel delivery to all units. Unit outage event ~8,400 MW
MISO [78], [79]	- As-Is System for the 2025-2026 winter period - based on NERC ES&D database, updated by the MISO, compiled by PJM staff - Load Shapes adjusted to the most recent monthly forecast provided by PJM - Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM - Operating Reserve 3,906 MW (30-min. 2,670 MW; 10-min. 1,236 MW)	

[78] Does not include the MISO-South (Entergy region).
[79] Provided list of planned maintenance outages occurring during the study window (11/1/2025 to 5/31/2026).

Table 10: Base and Severe Case Assumptions for Neighboring Areas

4. Study Results

4.1 Base Case Scenario

Figure 4 shows the estimated need for the indicated operating procedures in days/period for the November 2025 through March 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 **Appendices B, C** and **D**.

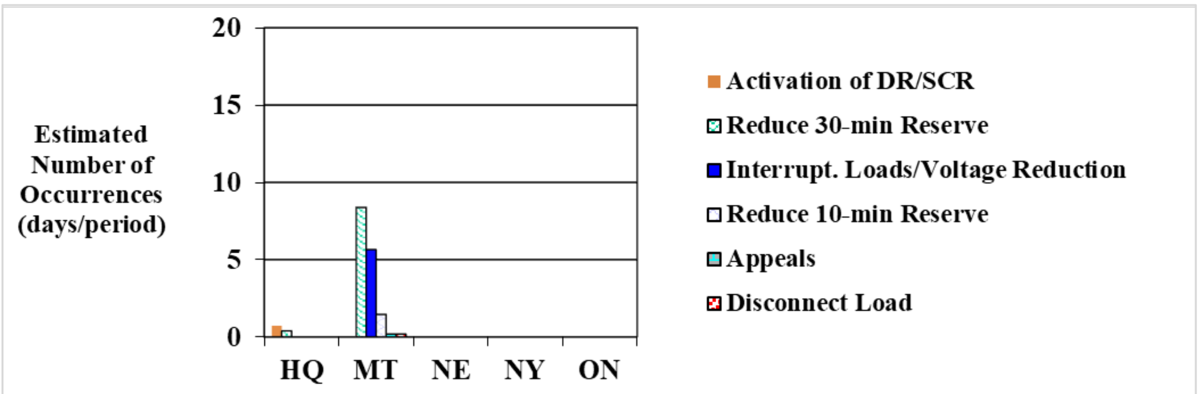

Figure 4: Estimated Use of Operating Procedure for Winter 2025-2026
Base Case Assumptions – 50/50 Peak Load Level

Figure 5 shows the corresponding results for the highest 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.

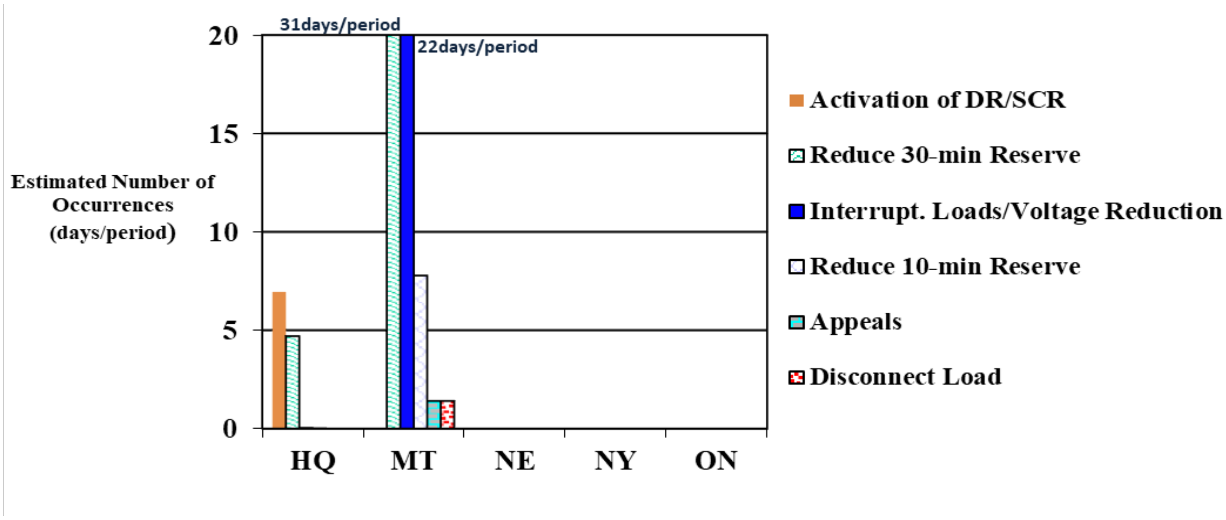

Figure 5: Estimated Use of Operating Procedures for Winter 2025-2026
Base Case Assumptions – Highest Peak Load Levels

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 **Appendices B, C** and **D**.

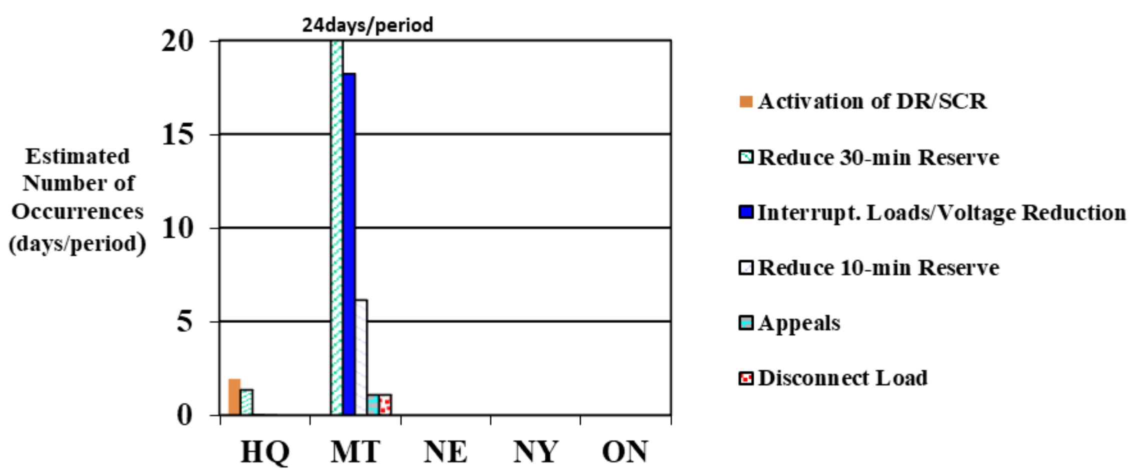

Figure 6: Estimated Use of Operating Procedure for Winter 2025-2026
Severe Case Assumptions – 50/50 Peak Load Level

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

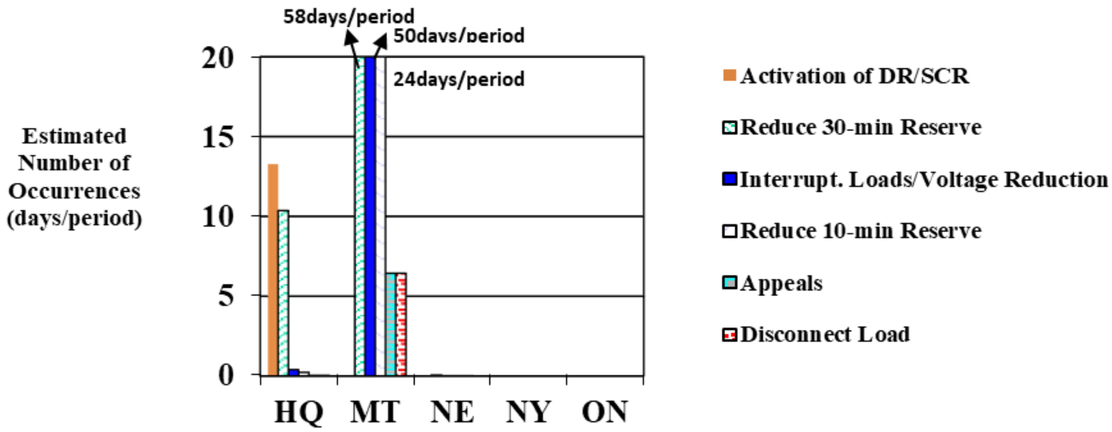

Figure 7: Estimated Use of Operating Procedure for Winter 2025-2026
Severe Case Assumptions – Highest Peak Load Level

5. Historical Review

Table 11 compares NPCC Area's actual 2024-2025 winter peak demands against the previous forecast assumptions based on the 2024-2025 Winter Assessment.

Area	Date	Actual (MW)	Forecast (MW)		Forecast
			50/50 Peak[80]	Higher Peak[81]	Month
Maritimes	01/22/2025	5,842	6,211	6,627	January
New England	01/22/2025	19,607	20,308	21,120	January
New York	01/22/2025	23,521	23,800	24,825	January
Ontario	01/22/2025	21,940	21,898	23,120	January
Québec	01/22/2025	39,871	40,312	42,618	January

Table 3: Comparison of NPCC 2024-2025 Actual and Forecast Winter Peak Loads[82]

A summary review of the last winter's demand and main operational issues are presented below, while a detailed historical weather review is presented in **Appendix G**.

[80] The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.
[81] The higher peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.
[82] See: seasonal-assessment/2024/npcc-winter-2024-2025-assessment-public.pdf.

5.1 Operational Review

NPCC

The NPCC Region experienced coincident peak demand of 107,681 MW on January 22, 2025, Hour Ending (HE) 08 EST. The all-time peak demand was 112,552 on Friday, February 3, 2023.

Maritimes

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

The actual internal winter peak demand of 5,842 MW occurred on January 22, 2025, at hour ending 9:00 EST, representing a mild winter. The previous Maritimes Area all-time high historical internal peak demand of 6,340 MW occurred on February 4, 2023.

During the 2024-2025 winter period, available capacity in Nova Scotia was below its target planning reserve margin due to a generator refurbishment project that extended beyond its planned completion date. The region saw a high volume of Energy Emergency Alerts (EEAs), with approximately 11 reports, including five EEA2 events. While the amount of load management was modest (~10 MW), the frequency of events was notable, primarily driven by multiple unplanned generation outages (more than two units) combined with high load during cold weather. Nova Scotia currently operates with only one synchronous tie to New Brunswick, though a project to upgrade this tie to 345 kV is underway, with completion expected by 2027.

New England

The New England weather in 2024-2025 winter was colder than the previous two winters across all months, with average temperatures 0.6°F below normal—the region's first below-average winter since 2014, and load increased by at least 5% each month relative to 2023-2024 winter.[83] The 2024-2025 New England system peak demand of 19,607 MW occurred on Wednesday, January 22, 2025, at hour ending at HE18 EST, slightly under the 50/50 forecast.

- ✓ The New England generation fleet and transmission system performed well overall.
- ✓ LNG supplies were adequate and send outs were minimal.

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[83] See: https://www.iso-ne.com/static-assets/documents/100024/2025-winter-quarterly-markets-report.pdf (page 34).

- ✓ Fuel oil supplies were adequate; inventories ended the winter ~0.8M gallons below starting inventories.[84]

- ✓ No OP-4 events occurred, and surplus generating capacity was available throughout the winter; no OP-21 Energy Alert or Energy Emergency actions were implemented last winter.

- ✓ During the Winter 2024-2025 period, there were the following Inventoried Energy Days:[85]

    - December 22, 2024
    - December 23, 2024
    - January 20, 2025
    - January 21, 2025
    - January 22, 2025

New York[86]

The 2024-2025 actual winter peak demand of 23,521 MW occurred on January 22, 2025, at HE18 EST. Winter 2024-2025 did result in below average temperatures for NYISO, though the system remained below the 50/50 forecast due to day-ahead activation of EDRP/SCR on January 21 and 22, reducing system load by approximately 500-600 MW.

The New York all-time winter peak load of 25,738 MW occurred on Tuesday, January 7, 2014.

Ontario[87]

Ontario's peak demand for 2024-2025 winter was 21,940 MW on January 22, 2025, at HE18 EST which was slightly above the normal peak forecast of 21,836 MW but below the extreme forecast of 23,137 MW. This peak included approximately 500 MW of demand reduction through the Industrial Conservation Initiative. The retirement of two Pickering nuclear units by the end of 2024 introduced high-voltage concerns in eastern Ontario and the Greater Toronto Area. These concerns were addressed through the commissioning of 500 kV shunt reactors and the operational use of 500 kV circuit removals for voltage control. Operational readiness activities conducted during the 2024–2025 period supported reliable system

[84]See: https://www.iso-ne.com/static-assets/documents/100022/2025-04-08_oil_graphs.pdf (slide 4).
[85]See: https://www.iso-ne.com/markets-operations/markets/inventoried-energy-program.
[86] See: Reliability and Market.
[87] See: https://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.

performance, and no significant operational issues were observed during the 2024–2025 Winter Operating Period.

Québec

Québec experienced a colder-than-average winter marked by three ice storms and strong wind events. The actual winter peak demand of 40,300 MW occurred on January 22, 2025, at hour ending 07:00 EST, slightly above the 50/50 forecast but below the historical peak of 42,790 MW (set on February 3rd, 2023). At the time of the Québec peak, exports of 3,343 MW and imports of 172 MW were sustained by the Québec Balancing Authority, for a net exchange (including losses) of 3,413 MW. The season was marked by significant weather events, including three ice storms and strong winds, which contributed to operational challenges. Despite these conditions, the system performed near forecasted levels, with several forced outages and import/export restrictions managed through emergency protocols.

6. Conclusions

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case conditions assuming the 50/50 peak load level, only the Maritimes and Québec Areas show a likelihood greater than 0.5 days/period of using their operating procedures designed to mitigate resource shortages[88] (activation of DR for Québec and reducing 30-min and 10-min reserves and initiating interruptible loads for Maritimes) during the 2025-2026 winter covering the period of November through March. The established Operating Procedures in Québec and the Maritimes are expected to be sufficient to maintain the balance between electricity supply and 50/50 forecast demand should resource shortages arise during the winter period. Occurrences less than 0.5 days per period are not considered significant.

The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated.

Higher Peak Load Levels

Under the highest peak load levels, the likelihood of activating emergency procedures increases. The Maritimes Area shows a notable likelihood of utilizing its Operating Procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves, public appeals and disconnecting firm load to maintain system reliability during the upcoming winter period. The Maritimes and Québec have varying reliance on external assistance during the winter 2025-2026 period for the base case higher peak load levels.

The higher peak 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.

Severe Case Scenario Summary

50/50 Peak Load Level

The Maritimes and Québec Areas show a cumulative likelihood of reducing their 30-min reserve requirements. Further, the Maritimes Area shows a greater cumulative likelihood of using more of their Operating Procedures designed to mitigate resource shortages during

[88] Likelihoods of less than 0.5 days/period are not considered significant.

the 2025-2026 winter period covering the period November thru March. This assessment suggests that operators in the Maritimes will likely need to implement emergency operating procedures and/or Emergency Energy Alerts (EEAs) during periods of unusually high demand or reduced resource availability. The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated.

Higher Peak Load Levels

For the higher load levels, the Maritimes and Québec Areas show greater cumulative likelihoods of using more of their Operating Procedures designed to mitigate resource shortages during the 2025-2026 winter covering the period November through March. Maritimes, Québec, and Ontario have an increased, varying reliance on external assistance during the winter 2025-2026 period. These results are primarily driven by the increase in the demand forecast.

These highest peak load conditions represent a combined probability of approximately 7%, highlighting potential risks under rare but severe system stress events.

Appendix A: Objective, Scope of Work and Schedule[89]

Objective

On a consistent basis, evaluate the near-term seasonal resource adequacy of NPCC Areas' reflecting NPCC Area and neighboring regional plans proposed to meet their respective resource adequacy planning criteria. The potential effects of proposed market mechanisms in NPCC and neighboring regions expected 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 2025-2026 period, consistent with the NPCC CO-12 WG's corresponding reliability assumptions.

Scope

The near-term seasonal analyses will update the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2025-2026 period in order to estimate the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) and Area identified Severe Case assumptions for the May to September 2024 summer and November 2024 to March 2025 winter seasonal periods, recognizing:

- uncertainty in forecasted demand,
- scheduled outages of transmission,
- forced and scheduled outages of generation facilities, including fuel supply disruptions,
- the impacts of Sub-Area transmission constraints,
- the impacts of proposed load response programs;

[89] TFCP Approved – February 7, 2025.

- historical hourly load shape analysis (considering the impact of DER and PV forecasts); and,
- as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

Reliability for the near-term seasonal analyses (2025–2026) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages, including expected reliability metrics and analysis supporting related NERC Reliability Assessment Subcommittee, probabilistic analysis requirements.

Schedule

A report combining the results of the CP-8 WG 2025-2026 Winter Probabilistic Multi-Area Reliability Assessment, and the corresponding CO-12 WG 2025-2026 Winter Reliability Assessment will be approved by the Reliability Coordinating Committee no later than December 1, 2025.

Appendix B: Detailed Study Results (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
2013-2014 Load Shape - 50/50 Load																						
Nov	-	-	-	-	0.330	0.188	0.007	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.000	-	-	-	0.491	0.283	0.073	0.007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.346	0.003	0.001	-	3.042	2.052	0.592	0.089	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.046	-	-	-	4.254	2.995	0.768	0.092	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.000	-	-	-	0.258	0.137	0.013	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.392	0.003	0.001	-	8.375	5.654	1.453	0.189	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013-2014 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	1.942	1.162	0.044	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	2.530	1.662	0.522	0.071	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	4.005	0.040	0.020	-	11.187	7.658	2.861	0.597	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.694	-	-	-	13.864	11.116	4.242	0.729	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.004	-	-	-	1.633	0.928	0.110	0.010	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	4.703	0.040	0.020	-	31.156	22.526	7.779	1.410	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 4: Base Case Assumptions - Expected Need for Indicated Operating Procedures (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
2013-2014 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	0.330	0.188	0.007	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.002	-	-	-	-	2.087	1.336	0.358	0.035	0.035	0.004	0.001	0.001	0.001	0.000	-	-	-	-	-	-	-	-	-	-
Jan	1.100	0.025	0.015	0.002	0.002	8.868	6.530	2.225	0.423	0.423	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.241	-	-	-	-	12.823	10.025	3.537	0.623	0.623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.004	-	-	-	-	0.260	0.137	0.013	0.001	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	1.348	0.026	0.015	0.002	0.002	24.368	18.214	6.139	1.082	1.082	0.004	0.001	0.001	0.001	0.000	-	-	-	-	-	-	-	-	-	-
2013-2014 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	1.942	1.162	0.044	0.002	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.034	-	-	-	-	9.017	6.531	2.278	0.303	0.303	0.055	0.017	0.010	0.010	0.003	-	-	-	-	-	-	-	-	-	-
Jan	6.925	0.385	0.223	0.034	0.033	21.116	18.205	8.427	2.332	2.332	-	-	-	-	-	0.002	0.001	-	-	-	-	-	-	-	-
Feb	3.341	0.009	-	-	-	24.970	23.206	13.294	3.791	3.791	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.060	-	-	-	-	1.666	0.927	0.109	0.010	0.010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	10.360	0.394	0.223	0.034	0.033	58.711	50.031	24.153	6.438	6.438	0.055	0.017	0.010	0.010	0.003	0.002	0.001	-	-	-	-	-	-	-	-

Table 13: Severe Case Scenario - Expected Need for Indicated Operating Procedures (days/period)

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 (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
2013-2014 Load Shape - 50/50 Load																						
Nov	-	-	-	-	1.625	0.756	0.017	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.000	-	-	-	1.581	0.836	0.169	0.015	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	1.008	0.004	0.002	0.000	16.490	9.859	2.120	0.286	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
Feb	0.077	-	-	-	26.160	15.673	2.789	0.304	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.000	-	-	-	1.176	0.535	0.037	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	1.085	0.004	0.002	0.000	47.033	27.659	5.132	0.607	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
2013-2014 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	9.967	4.908	0.135	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.000	-	-	-	9.642	5.551	1.321	0.158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	13.637	0.066	0.024	0.001	75.352	45.900	12.290	2.282	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
Feb	1.158	-	-	-	117.021	78.134	18.376	2.744	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.007	-	-	-	8.215	4.018	0.327	0.027	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	14.802	0.066	0.024	0.001	220.197	138.511	32.449	5.214	-	-	-	-	-	-	-	-	-	-	0.000	0	-	-

Table 14: Base Case Assumptions - Expected Need for Indicated Operating Procedures (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
2013-2014 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	1.625	0.756	0.017	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.006	0.000	-	-	-	8.627	4.926	0.958	0.085	0.085	0.011	0.003	0.002	0.002	0.000	-	-	-	-	-	-	-	-	-	-
Jan	3.819	0.058	0.029	0.003	0.003	64.600	40.914	10.179	1.751	1.751	-	-	-	-	-	0.000	0.000	-	-	-	0.000	-	-	-	-
Feb	0.509	0.001	0.000	-	-	118.910	78.402	18.539	2.873	2.873	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.006	-	-	-	-	1.180	0.535	0.037	0.003	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	4.341	0.059	0.029	0.003	0.003	194.942	125.532	29.729	4.712	4.712	0.011	0.003	0.002	0.002	0.000	0.000	0.000	-	-	-	0.000	-	-	-	-
2013-2014 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	9.967	4.908	0.135	0.003	0.003	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.093	0.000	-	-	-	46.291	28.797	6.851	0.789	0.789	0.153	0.035	0.023	0.023	0.006	-	-	-	-	-	-	-	-	-	-
Jan	39.267	0.888	0.441	0.050	0.049	222.360	152.901	48.818	11.332	11.332	-	-	-	-	-	0.005	0.002	-	-	-	0.000	-	-	-	-
Feb	7.275	0.012	0.000	-	-	351.156	272.786	94.243	20.434	20.434	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.097	-	-	-	-	8.278	4.014	0.328	0.027	0.027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	46.732	0.901	0.441	0.050	0.049	638.052	463.406	150.374	32.585	32.585	0.154	0.035	0.023	0.023	0.006	0.005	0.002	-	-	-	0.000	-	-	-	-

Table 15: Severe Case Scenario - Expected Need for Indicated Operating Procedures (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
2013-2014 Load Shape - 50/50 Load																						
Nov	-	-	-	-	103.4	46.5	0.8	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.0	-	-	-	105.8	53.6	8.4	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	20.5	1.3	0.4	0.0	1649.4	919.3	176.4	19.2	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-
Feb	0.3	-	-	-	2419.2	1387.2	213.1	18.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.0	-	-	-	65.1	28.3	0.8	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	20.8	1.3	0.4	0.0	4342.9	2434.9	399.5	38.3	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-
2013-2014 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	679.7	321.6	7.4	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.0	-	-	-	755.6	410.5	75.7	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	309.7	19.7	6.6	0.1	9120.5	4983.5	1193.0	176.3	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-
Feb	4.8	-	-	-	13039.0	8130.8	1610.9	185.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.0	-	-	-	511.6	239.5	8.6	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	314.5	19.7	6.6	0.1	24106.4	14085.8	2895.5	367.6	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-

Table 16: 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
2013-2014 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	103.4	46.5	0.8	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.0	0.0	-	-	-	699.9	375.5	63.2	4.4	4.4	4.3	1.2	0.8	0.8	0.1	-	-	-	-	-	-	-	-	-	-
Jan	159.1	23.2	11.3	1.2	1.2	7344.3	4284.5	966.6	137.6	137.6	-	-	-	-	-	0.1	0.0	-	-	-	0.0	-	-	-	-
Feb	7.4	0.1	0.0	-	-	13133.5	8200.9	1654.7	202.5	202.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	0.2	-	-	-	-	65.4	28.3	0.8	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	166.8	23.3	11.3	1.2	1.2	21346.5	12935.7	2686.0	344.6	344.6	4.3	1.2	0.8	0.8	0.1	0.1	0.0	-	-	-	0.0	-	-	-	-
2013-2014 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	679.7	321.6	7.4	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	0.7	0.0	-	-	-	4351.7	2504.5	505.4	43.3	43.3	61.4	18.3	12.5	12.5	2.1	-	-	-	-	-	-	-	-	-	-
Jan	2338.6	356.4	173.6	18.8	18.1	34340.1	19585.7	5545.1	1014.6	1014.2	-	-	-	-	-	1.1	0.2	-	-	-	0.1	-	-	-	-
Feb	112.8	1.0	0.0	-	-	53005.8	36647.7	10053.6	1647.3	1647.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	3.2	-	-	-	-	516.0	239.5	8.6	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	2455.3	357.4	173.6	18.8	18.1	92893.3	59299.0	16120.1	2705.6	2705.2	61.5	18.3	12.5	12.5	2.1	1.1	0.2	-	-	-	0.1	-	-	-	-

Table 17: 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[90] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

1. Modeling Technique

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

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

2. Reliability Indices

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

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

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

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

[90] See: https://www.gevernova.com/consulting/planos/resource-adequacy.

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

3. Resource Allocation Among Areas

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

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

4. 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:

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

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 among energy that they can storage. 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.

5. Transmission System

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

6. Contracts

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

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Appendix 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*.[91] 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.

New England

The New England generating unit ratings were consistent with their seasonal capability as reported in the 2025 CELT report.[92] Active Demand Capacity Resources and capacity imports are based on their Capacity Supply Obligations of the 3rd annual Reconfiguration Auction of Capacity Commitment Period of 2025-2026.

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 2025–2026 Capability Year*, dated January 21, 2025, and that New York State will meet the capacity requirements described in the *New York Control Area Installed Capacity Requirements for the Period May 2025–April 2026*, New York State Reliability Council, Technical Study Report, dated December 6, 2024.[93]

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).[94]

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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[91] See: https://www.npcc.org/reliability-services?category=Resource%20Adequacy.
[92] See: https://www.iso-ne.com/system-planning/system-plans-studies/celt.
[93] See: https://www.nysrc.org/wp-content/uploads/2024/12/2025-IRM-Study-Technical-Report_Final_12062024_clean.pdf.
[94] See: https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

assessment of Ontario's electricity system From October 2025 to March 2027 - September 18, 2025.[95]

Québec

The Planned resources are consistent with the NERC 2025-2026 *Winter Reliability Assessment*.[96]

Resource Availability

Maritimes

Individual generating unit maintenance assumptions are based on approved maintenance schedules for the study period.

New England

This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period (2020-2024). 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 2025–2026 Capability Year*[97] and the *New York Control Area Installed Capacity Requirement for the Period May 2025 to April 2026* New York State Reliability Council, December 6, 2024, report.[98]

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*

[95] See: Reliability Outlook (ieso.ca).
[96] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[97] See: https://www.nyiso.com/documents/20142/49410485/2025-2026-LCR-Report-Clean.pdf/
[98] See: https://www.nysrc.org/wp-content/uploads/2024/12/2025-IRM-Study-Technical-Report_Final_12062024_clean.pdf.

assessment of Ontario's electricity system From October 2025 to March 2027 - September 18, 2025.[99]

Québec

Available capacity is derived from the most recent calendar five-year (2017-2022) period forced outage data. Units are modeled in the MARS Program using a multi-state representation that represents a seasonal Equivalent Forced Outage Rate on Demand (EFORd). Planned and scheduled maintenance outages are modeled based data from Hydro-Québec and IPPs.

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,

[99] See: Reliability Outlook (ieso.ca).

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

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

Hourly output profiles are used to model solar and wind resources. The total Network Resource Capability (NRC) of solar resources is calculated by aggregating them by zone and modeling their hourly output profiles for five historical years (2020–2024) based on their simulated output over the previous five years. With every sample draw, GE MARS chooses at random one of the five profiles. Five years' worth of hourly production profiles are used to model wind resources. In GE MARS, every sample draw corresponds to a randomly selected profile.

New York

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

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

Ontario

Solar generation is aggregated by IESO zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production.

Solar generation uses 10 years of simulated hourly profiles. Solar generators are matched to the closest simulated site and technology type (ground-mount or rooftop), and then output is scaled relative to installed capacity.

Québec

Behind-the-meter generation (solar and wind) is estimated at approximately 49 MW of installed capacity for the 2025-2026 winter. Contributions of BTM generation is negligible during the winter peak-period (~1 MW) and doesn't affect the load monitored from a network perspective. Front-of-the-meter PV installed capacity is expected to be 9.5 MW by the end of this year. The impact of this resource at peak time period is not significant.

Wind

Maritimes

Each sub-area within the Maritimes has a series of annual wind shapes corresponding to years from 2012 through 2024. The model randomly selects from all those shapes and 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.

The data is considered typical having had substantially all the existing Maritimes Area wind resources by that time and no major outages due to icing or other abnormal weather or operating problems.

New England

Hourly output profiles are used to model solar and wind resources. The total Network Resource Capability (NRC) of solar resources is calculated by aggregating them by zone and modeling their hourly output profiles for five historical years (2020–2024) based on their simulated output over the previous five years. With every sample draw, GE MARS chooses at random one of the five profiles. Five years' worth of hourly production profiles are used to model wind resources. In GE MARS, every sample draw corresponds to a randomly selected profile.

New York

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

Ontario

Wind generation is aggregated by IESO zone and 30 years of simulated hourly profiles are used. The MARS model randomly selects a different yearly simulated profile during each iteration. Wind generators are matched to the closest simulated site, and then output is scaled relative to installed capacity.

Québec

Wind generation is modeled using eight years of hourly historical data (2017-2024), 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

About 440 MW of Active Demand Capacity Resources are expected to be available to offer to sell demand-reductions in the energy market.

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, 1,487 MW of SCRs were modeled. At the time of the winter peak, this amount was discounted to 1,005 MW, based on historical availability.

Ontario

The demand measures are approximately 1,100 MW for the winter period.

Québec

In Québec, Demand Response (DR) programs are specifically designed for peak-load reduction during winter operating periods. Some DR is expected to remain available for the summer period. DR consists of interruptible demand programs mainly for large industrial customers. DR programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand. Interruptible load program specifications differ among programs and participating customers. They usually allow for one or two calls for reduction per day and between 20 to 120 hours load interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed. Before the peak period, generally during the fall season, all customers are regularly contacted in order to reaffirm their commitment to provide capacity when called, during peak periods. DR programs are modeled as resources with their constraints and limitations in the resource adequacy model, GE MARS.

Appendix G: Previous Winter Review

Weather

Highlights – (January-March 2025)[100]

The year-to-date (January-March) average contiguous U.S. temperature was 37.0°F, 1.8°F above average, ranking in the warmest third of the record for this period.

For the January-March period, temperatures were near- or above average across most of the contiguous U.S., including the entire northeast region. No state experienced a top-10 coldest event for this three-month period.

The contiguous U.S. average maximum (daytime) temperature during January-March was 48.5°F, 2.4°F above average, ranking in the warmest third in the historical record. Above-average temperatures were observed across much of the conterminous U.S., while much above-average temperatures were observed in parts of the Southwest and Pacific Coast.

The contiguous U.S. average minimum (nighttime) temperature during this three-month period was 25.4°F, 1.2°F above average, ranking in the warmest third in the historical record. Near-average nighttime temperatures were observed across nearly all of the conterminous U.S.

Based on the NOAA Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during January-March was 73 percent of average and was the 26th-lowest value on record.

The U.S. Climate Extremes Index (USCEI) for the year-to-date period was 47 percent below average, ranking in the lower third of the 116-year period of record. Extremes across nearly all indicators were below average, except for notably dry PDSI conditions. The USCEI is an index that tracks extremes (occurring in the upper or lower 10 percent of the record) in temperature, precipitation and drought across the contiguous United States.

On the regional scale, only the Southwest was the only above average region, while the Northwest had its third lowest CEI on record for this period.

[100] NOAA National Centers for Environmental Information, Monthly National Climate Report for March 2024, published online April 2024, retrieved on August 18, 2025 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202503.

Northeast Region

December[101]

December was the only cooler-than-normal month in 2024 and featured variable precipitation, chipping away at drought conditions in the Northeast.

In December, the Northeast had an average temperature of 29.4 degrees F, which is 0.4 degrees F below normal. Ten states in the Northeast were cooler than usual, with temperatures ranging from 1.4 degrees F below normal in New Jersey to 0.5 degrees F above normal in Maine.

The Northeast also experienced close to average precipitation in December, with 3.70 inches of precipitation, which is 98 percent of normal. The 12 Northeast states varied much more individually, with precipitation ranging from 64 percent of normal in Delaware to 146 percent in Rhode Island, which had its 13th wettest December. Providence, Rhode Island, had its wettest December since the record began in 1895.

The U.S. Drought Monitor from December 3 indicated that 65 percent of the Northeast was in drought, and 33 percent classified as abnormally dry. Extreme drought was present in Massachusetts. Wetter conditions in December helped reduce drought levels all 12 Northeast States. By December 31, the Drought Monitor reported 42 percent of the Northeast in drought, and 31 percent as abnormally dry. Throughout December, streamflow and groundwater levels were sometimes below normal in western New York, western Pennsylvania, southern West Virginia, and areas from eastern West Virginia through Maryland and southern Pennsylvania to southern New Jersey, with some gauges recording record low levels.

Rochester, New York had its second-latest date for measurable snow on record, receiving 1.8 inches on December 2. An atmospheric river brought heavy rainfall and winds to much of the East Coast on December 11, reducing drought conditions in an area that had not seen a significant rain event since August. This caused several sites in the Northeast to experience top 10 wettest days for December. The storms also included wind gusts, peaking between 30 and 66 mph in New England, resulting in power outages for tens of thousands of customers. Following this event, multiple sites near the Great Lakes in New York saw heavy snow. Wales had its snowiest December since its records began in 1986.

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[101] NOAA National Centers for Environmental Information, Monthly National Climate Report for December 2023, published online January 2024, retrieved on October 28, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202412.

January[102]

In January 2025, the Northeast experienced a colder than normal January, with an average temperature of 21.6°F, which is 2.5°F below normal. Across the 12 Northeast states, average temperatures for January ranged from 7.2°F below normal in West Virginia to 1.1°F above normal in Maine, the only warmer-than-normal state.

In January 2025, the Northeast experienced its eighth driest January since 1895, with 1.66 inches of precipitation, which is 51% of the normal amount. Precipitation levels ranged from 26% of normal in New Jersey to 82% in West Virginia. 11 states recorded one of their top 15 driest Januarys, with New Jersey ranking third; Delaware fourth; Connecticut and Pennsylvania fifth; Maryland sixth; Massachusetts, New Hampshire, and Vermont eighth; Maine, twelfth; Rhode Island, fourteenth; and New York eighteenth.

On January 7, the U.S. Drought Monitor showed that 34% of the Northeast was in drought, and 32% was abnormally dry. Extreme drought was present in parts of New Jersey and Delaware, while severe and/or moderate drought was present in a path from Maryland to Maine. Low precipitation caused areas of severe drought to expand in southeastern Maryland and central New Jersey, and abnormal dryness to expand in central New York. On January 28, the U.S. Drought Monitor still showed 34% of the Northeast in drought, and 39 percent was abnormally dry. Record or near-record low streamflow was found in a few areas to start the m o nth but became more widespread later in the month, particularly from Maryland to southeastern New York. Groundwater levels were below normal or lower for a large portion of the region.

The beginning of January saw periods of heavy snow, particularly near the Great Lakes. Central New York received 75 inches of snow between January 1 and 5. January 6 saw a storm with additional snowfall in Maryland and Delaware. Multiple winter storms throughout the month resulted in frequent cold air outbreaks which caused school delays and multiple deaths and emergency room visits.

February[103]

The Northeast had a relatively average February with an average temperature of 25.6 degrees F, 0.8 degrees F below normal, with 10 states experiencing below average temperatures. Across the 12 Northeast states, the average temperatures ranged from 2.6 degrees F below normal in Delaware to 0.1 degrees below normal in Maine. This marked the first January since 2018 with a colder than average winter in the Northeast.

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[102] NOAA National Centers for Environmental Information, Monthly National Climate Report for January 2024, published online February 2024, retrieved on October 28, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202501.
[103] NOAA National Centers for Environmental Information, Monthly National Climate Report for February 2024, published online March 2024, retrieved on October 28, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202502.

The Northeast experienced a broad spectrum of precipitation in February, seeing 3.26 inches of precipitation, 118 percent of normal. This ranged from 88 percent of normal in New Jersey to 172 percent of normal in West Virginia.

On February 4, the U.S. Drought Monitor showed 35 percent of the Northeast in Drought and 37 percent as abnormally dry. In extremely dry areas, frequent storms reduced dryness, such as extreme drought in Delaware and southern New Jersey. On February 25, the U.S. Drought Monitor showed 31 percent of the Northeast in drought and 36 percent of the region as abnormally dry. However, groundwater levels remained below normal or lower for a large portion of the Northeast, with record-low levels in coastal areas from Maryland to Maine.

Several notable storms occurred in the Northeast during February. From February 5 to 7, a storm brought up to 12 inches of snowfall in Northern New York and Northern New England. Further south in western Maryland, freezing rain left a coating of ice between 0.25 and 0.50 inches thick. From February 8 to 9, freezing rain affected parts of western Maryland and snowfall of up to 12 inches was reported in southern Maine. This storm caused reports of rockslides and floodwaters which resulted in road closures. From February 15 to 17, another mixed precipitation major storm moved through the Northeast. The ice and snow resulted in reports of downed tree branches and power lines. The storm's wake saw strong winds and cold air pushed into the region, with the highest gusts ranging from 40 to 60 mph. Power outages, road closures, and at least one fatality occurred. Whiteout conditions in central New York contributed to a multi-vehicle pileup that closed the New York State Thruway. Heavy snow from January continued in many locations in central New York, with Syracuse and Rochester ranking as the second greatest number of days with measurable snow on record in January and February combined.

March[104]

The Northeast wrapped up March with an average temperature of 38.9 degrees F, 5.0 degrees F above normal. Average temperatures for March for the 12 Northeast states ranged from 3.6 degrees F above normal in Maine to 5.0 degrees F above normal in New York., which tied its warmest March temperature with a high of 82 degrees F on March 29 in Islip, New York. This March ranked among the 20 warmest for all 12 Northeast states since 1895: Connecticut, Massachusetts, and Rhode Island, 12th warmest; New York and Pennsylvania, 14th warmest; Vermont, 15th warmest; New Hampshire, 17th warmest; Maine, 18th warmest; and West Virginia, 20th warmest.

The Northeast experienced a relatively dry March, accumulating 2.78 inches of rainfall, which was 78 percent of the average. The amount of rain in March across the 12 Northeast states varied from 44 percent of the average in West Virginia, to 120 percent of the average in

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[104] NOAA National Centers for Environmental Information, Monthly National Climate Report for March 2025, published online April 2024, retrieved on October 28, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202503.

Maine. Among the records, March 2025 was the 4th driest March for West Virginia and 12th for Pennsylvania.

The U.S. Drought Monitor from March 4 showed 31 percent of the Northeast in drought and 36 percent of the region as abnormally dry. During March, some coastal and northern parts of the region saw beneficial precipitation that chipped away at drought and abnormally dry conditions. For instance, extreme, severe, and moderate drought contracted in New Jersey, while severe drought was removed from New England. However, inland and southern areas generally missed out, allowing drought and abnormal dryness to expand. For example, in West Virginia, severe drought returned, and moderate drought expanded. The U.S. Drought Monitor from March 25 showed 27 percent of the Northeast in drought and 38 percent of the region as abnormally dry.

An area from West Virginia to northern New York saw severe weather on March 16. Multiple areas of damaging straight-line winds of up to 100 mph were noted in western and central Pennsylvania and just across the border in western New York. A wind gust of 89 mph was clocked at the Latrobe Airport in Pennsylvania, with the National Weather Service stating that it was the site's "third highest wind gust on record." Non-thunderstorm related wind gusts also brought down some trees and power lines in several parts of the Northeast. Additionally, multiple locations close to the coast from Maryland to Maine saw over an inch of precipitation between March 16 and 18, with the greatest amounts of around 4 inches in southern Delaware and eastern Maryland. The precipitation combined with milder temperatures and snowmelt contributed to localized flooding, including from ice jams, in parts of Maine through March 19. Back-to-back storms moved through the region from March 29 to 31. Meanwhile, parts of New York and New England were colder and saw snow and ice. The greatest storm snow totals were around 10 inches in northern New York, while the greatest freezing rain totals were around 0.50 inches in northern New York and southern New Hampshire. Multiple locations across the Northeast saw record or near record low snowfall this March. Of the region's 35 major sites, 16 saw their least snowy March on record, in many cases tying with multiple other years. However, it was the first March on record that Allentown, Pennsylvania, did not record even a trace of snow and one of only five or fewer Marches with no snow in places like Harrisburg, Pennsylvania, and Central Park, New York, which both have records back to the late 1800s. Additionally, it was among the 20 least snowy Marches for another 12 of the major sites.

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

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