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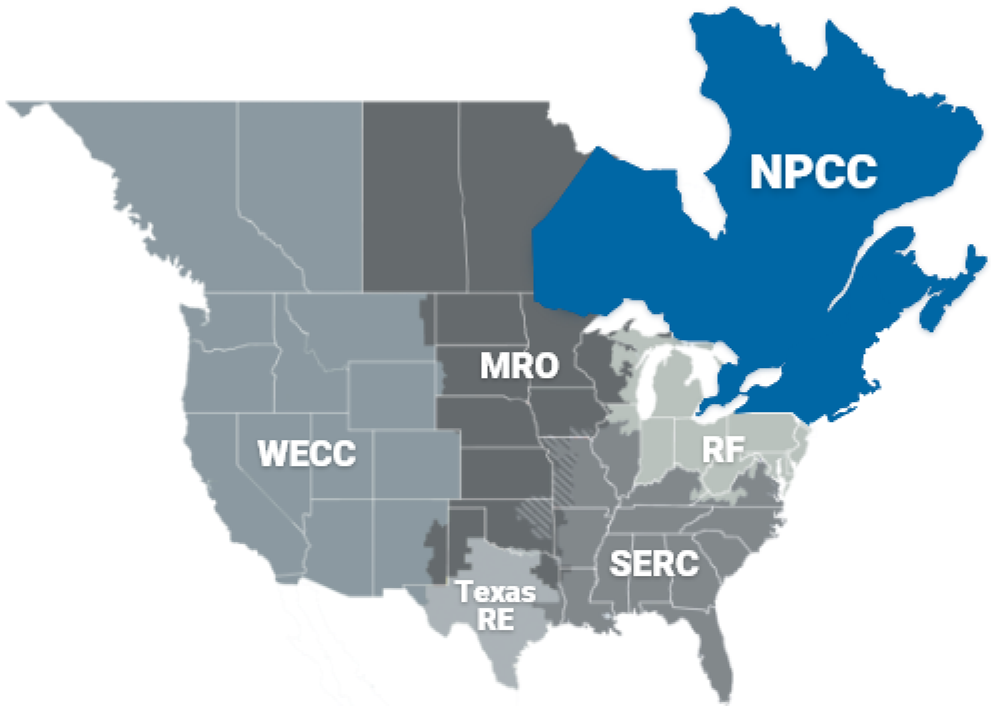
Northeast Power Coordinating Council

Reliability Assessment
For
Winter 2023-2024



Approved by the RCC
December 5, 2023

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

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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 2023-24 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 31, 2023, 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 2023/24 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. For the remaining associated Balancing Authority Areas, under low likelihood, high demand severe case conditions, necessary strategies and procedures are in place to provide load relief and manage operational challenges/emergencies. NPCC Area and regional peak loads have been trending upwards in recent years due to a variety of factors. The resource and transmission assessments in this report are mere snapshots in time and base case studies. Results of the NPCC CP-8 Working Group's seasonal, multi-area probabilistic reliability assessment are included in Chapter 9 of this report with supporting documentation provided in Appendix VIII.

A Sensitivity Case was analyzed using a probabilistic approach based on Severe Resource unavailability and the February 3 - 4, 2023 system conditions repeated through a two-week period. The intention of the Sensitivity Case is to assess the ability of the NPCC region to ensure regional reliability and sufficient energy to winter-peaking Areas for the duration of the event under the assumed conditions. The results illustrate that, should the low likelihood, assumed system conditions occur, the New York, New England, Ontario, and Québec Areas show no loss of load for the duration of the event. Assumed resources are sufficient to avoid loss of load for these Areas. Further, the Maritimes and Québec Area's demonstrated a reliance on external assistance to help reduce the need for Emergency Operating Procedures throughout the duration of the event. Additionally, the results demonstrate an increasing cumulative risk to interrupting Maritimes firm load for the first week of the period, eventually reaching 0.29 days/period LOLE by the end of the period, under the assumed load levels and resource unavailability. The associated risk is distributed across the days of the cold snap period. Additional information is 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; most notably New England with its constrained natural gas pipeline infrastructure, has significant reliance on global LNG supplies which are projected to be in high demand this winter, and fuel oil inventories that are as expected entering this winter, and is at increased risk during periods of extended cold weather. It is critical that generation owners in the region have plans in place to replenish fuel supplies to maintain reliability of the Bulk Electric System. 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 112,217 MW is anticipated to occur during the peak week beginning January 21, 2024. The capacity outlook indicates a forecasted Net Margin for that week of 16,909 MW. This equates to a net margin of 15.1% in terms of the 112,217 MW forecasted peak demand. It is important to note that NPCC Area and NPCC regional-coincident peak demands have increased in recent years, with the new all-time historical peak being set during the winter 2022-23 period. While the forecasted net margin for the NPCC Region is materially lower (-3,670 MW) for this upcoming winter compared to the last winter's forecast, driven by increases in forecasted peak demands (~1,600 MW) and reductions in available resources (~ -1,000 MW), the region's spare operable capacity under forecasted conditions [1] is estimated to be substantial (capacity over and above reserve requirements) – ranging from approximately 16,900 to 33,200 MW.

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

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 2023-24 Winter Operating Period[2] 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 2023-24 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.

[2] For this report, the Winter Operating Period evaluation will include operating conditions from the week beginning November 26, 2023, through the week beginning March 24, 2024.

3. Demand Forecasts for Winter 2022-23

The coincident 50/50 forecasted peak demand for NPCC over the 2023-24 Winter Operating Period is 112,217 MW, which is expected during the week beginning January 21, 2024. The 50/50 forecasted peak demand for NPCC is 1,578 MW higher than the previous Winter Operating Period forecast. The NPCC Winter 2022-23 actual coincident peak demand of 112,552 MW occurred on February 3, 2023 at HE19 EST. This represented the NPCC all-time peak demand, exceeding the previous value of 112,384 MW on August 1, 2006. Prior to the 2022-2023 Winter Operating Period, the historical NPCC winter peak demand was 111,801 MW on January 2, 2014. 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. TransÉnergie, 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.

The method 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 the Tables below are the Reliability Coordinator Area forecasts for the Winters 2023-2024 and 2022-2023. The Figures below represent the week-by-week demand profiles of each Area's Winter 2023-24 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

Table 3-1: Maritimes Area Forecasts (MW)

	Winter 2023-24 Forecasted Peak: week beginning January 14, 2024	Winter 2022-23 Forecasted Peak: week beginning January 22, 2023	Winter 2022-23 Actual Peak: February 4, 2023 at HE10 EST
50/50	5,863	5,784	6,340
90/10	6,254	6,168	
Above 90/10	6,435	6,348	

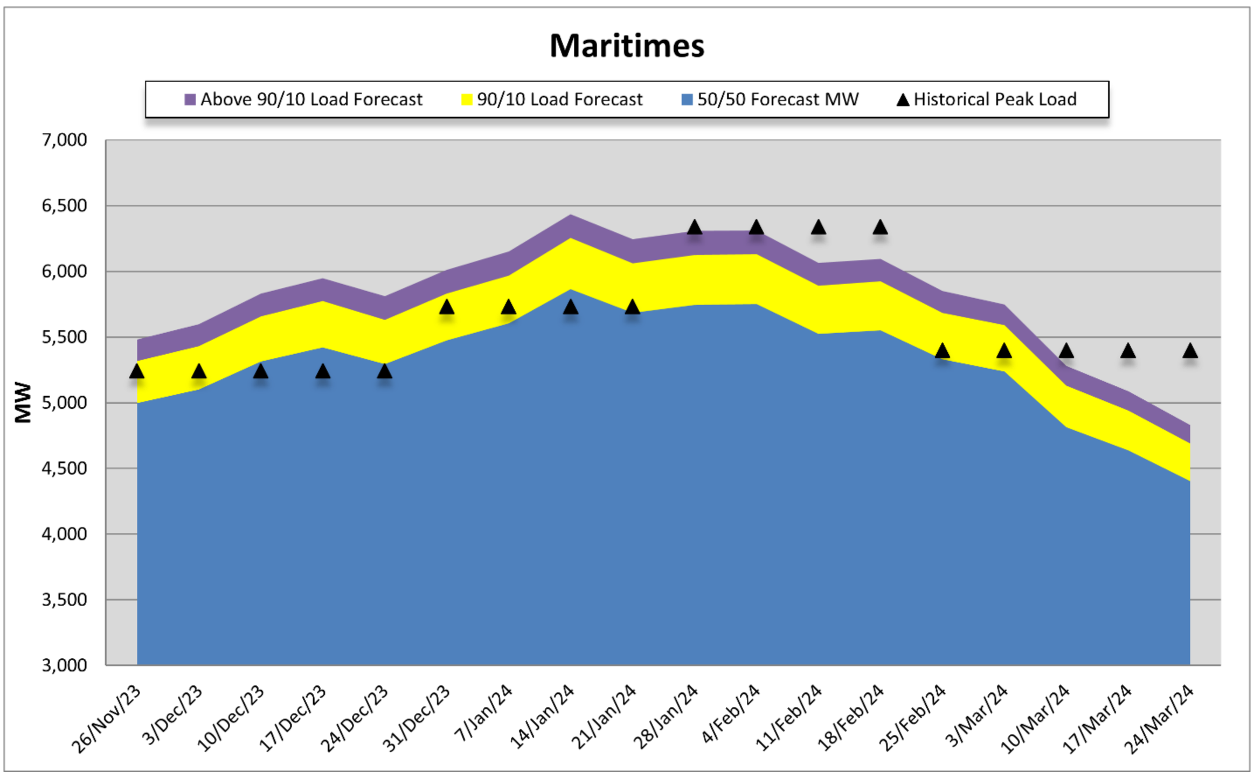


Figure 3-1: Maritimes Winter 2023-24 Weekly Demand Profile [3]

[3] The Maritimes Area Historical Peak Load profile data provided is based on the historical monthly peak for the years 2004 – 2023.

New England

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

	Winter 2023-24 Forecasted Peak: weeks beginning January 7 - 21, 2024	Winter 2022-23 Forecasted Peak: weeks beginning January 8 - 22, 2023	Winter 2022-23 Actual Peak: February 3, 2023 at HE19 EST
50/50	20,269	20,009	19,529
90/10	21,032	20,695	
Above 90/10	21,746	21,238	

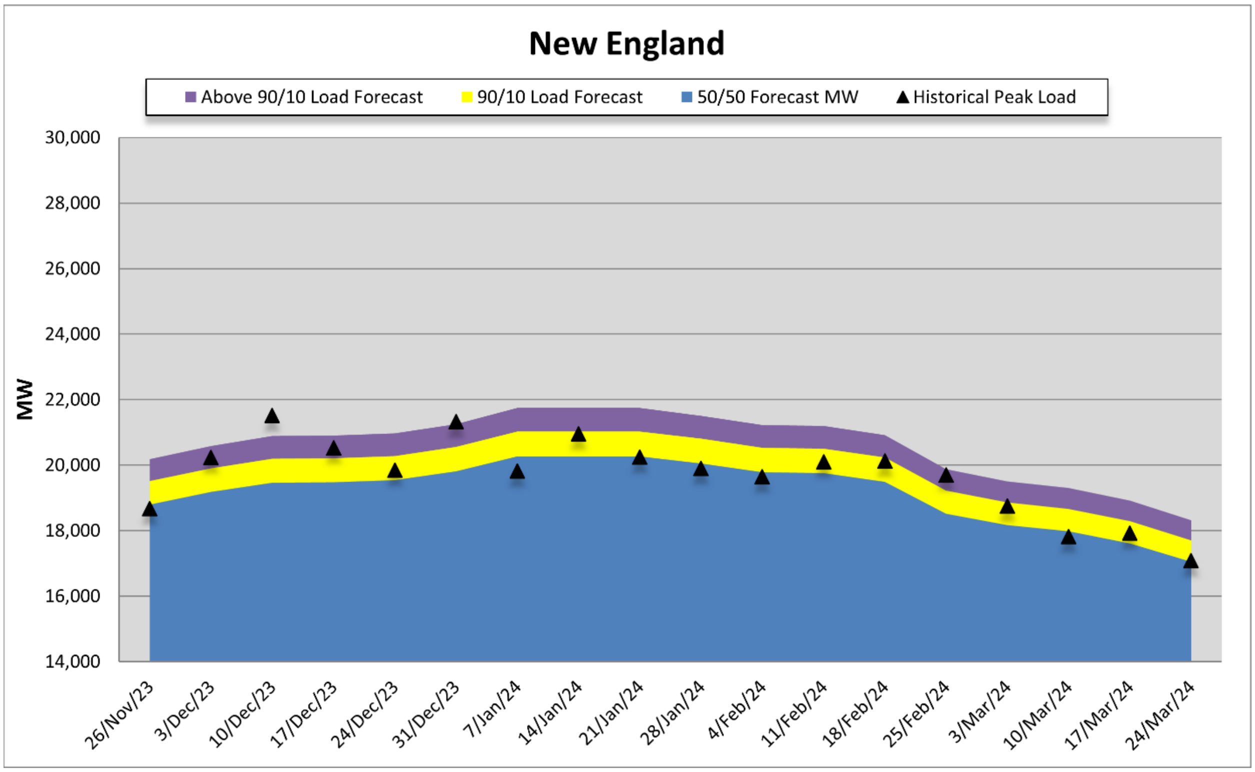


Figure 3-2: New England Winter 2023-24 Weekly Demand Profile[4] [5]

[4] 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 2023-2024 winter peak demand is during the weeks beginning January 7, 14, and 21, 2024.

[5] The New England Area Historical Weekly Peak Loads for the years 2014 - 2023.

New York

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

	Winter 2023-24 Forecasted Peak: during weeks of December , 2023 through February , 2024*	Winter 2022-23 Forecasted Peak: during the months of December 4, 2022 through February 19, 2023	Winter 2021-22 Actual Peak: February 3, 2023 at HE19 EST
Normal	24,220	23,893	23,369
90/10	25,236	25,122	
Above 90/10	27,022	26,086	

**Note: For Winter 2023-24, it is expected that the winter peak could occur at any time during the months of December 2023 through February 2024.*

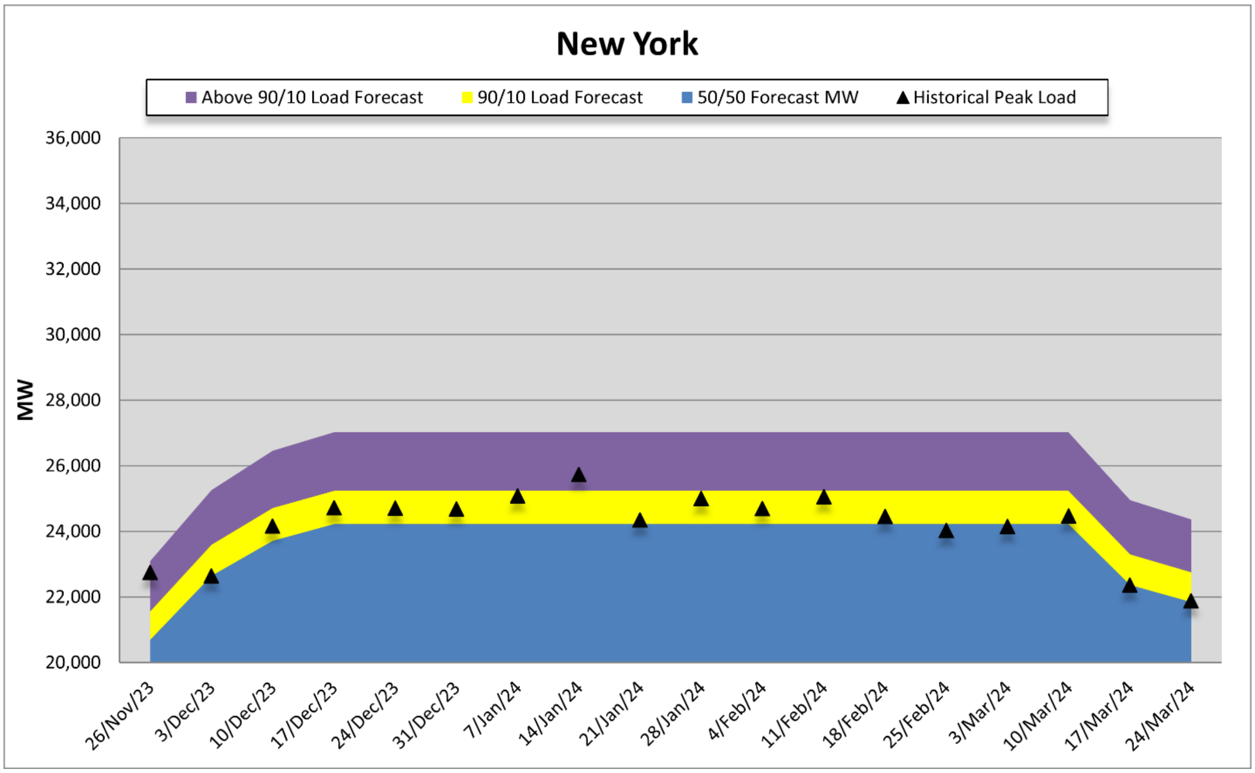


Figure 3-3: New York Winter 2023-24 Weekly Demand Profile[6]

[6] The New York Area Historical Weekly Peak Loads for the years 2006-2023.

Ontario

Table 3-4: Ontario Area Forecasts (MW)

	Winter 2023-24 Forecasted Peak: week of January 21, 2024	Winter 2022-23 Forecasted Peak: week of January 22, 2023	Winter 2022-23 Actual Peak: February 3, 2023 at HE19 EST
50/50	21,402	21,255	21,388
90/10	22,640	22,258	
Above 90/10	22,909	22,583	

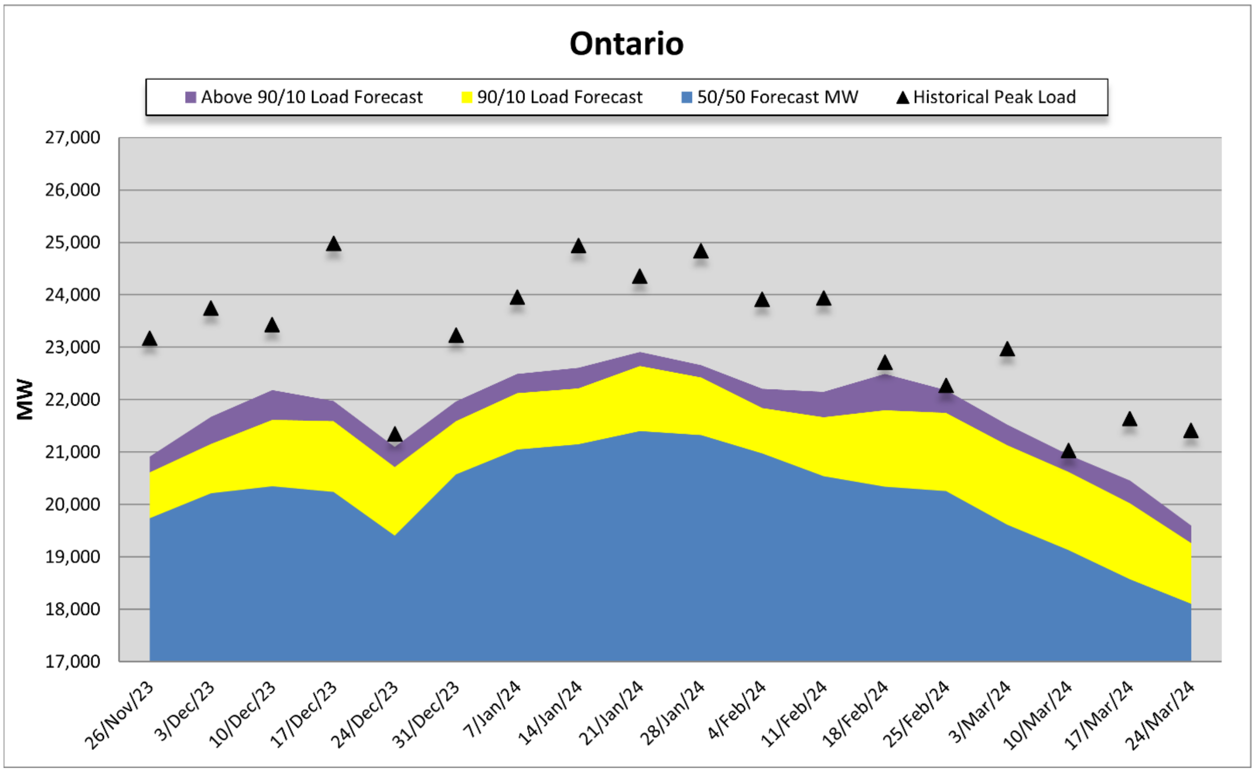


Figure 3-4: Ontario Winter 2023-24 Weekly Demand Profile[7]

[7] The Ontario Area Historical Weekly Peak Loads for the years 2002-2023.

Québec

Table 3-5: Québec Area Forecasts (MW)

	Winter 2023-24 Forecasted Peak: week of January 24, 2024	Winter 2022-23 Forecasted Peak: week of January 22, 2023	Winter 2022-23 Actual Peak: on February 3, 2023 at HE18 EST
Normal	40,641	39,699	42,790
90/10	43,008	40,487	
Above 90/10	44,284	43,100	

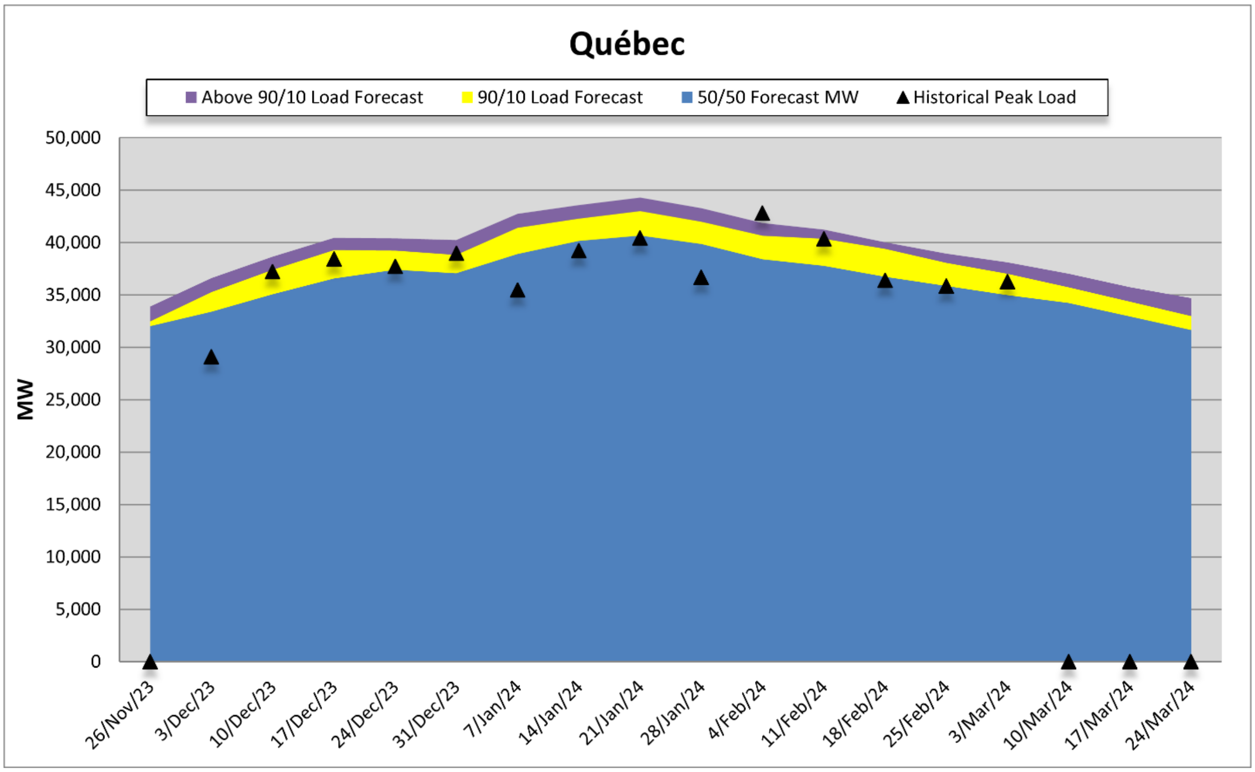


Figure 3-5: Québec Winter 2023-24 Weekly Demand Profile [8] [9]

[8] The Québec Area Historical Peak Load profile ranges from 2003-2023.

[9] Historical Weekly Peak Loads for the weeks beginning November 26, March 10, March 17 and March 24 are unavailable.

4. Resource Adequacy

NPCC Summary for Winter 2023-24

The assessment of resource adequacy indicates the week with the highest forecasted coincident NPCC demand is the week beginning January 21, 2024 (112,217 MW). Detailed projected load and capacity forecast summaries specific to NPCC and each Area are included in Appendix I.

In Appendix I, **Table AP-1** is the NPCC Load and Capacity summary for the 2023-24 Winter Operating Period. Appendix I, Tables **AP-2** through **AP-6**, contain the load and capacity summary for each NPCC Reliability Coordinator area. Each entry in Table **AP-1** is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator areas.

Table 4-1 below summarizes the NPCC forecasted load and resource adequacy for the peak week beginning January 21, 2024 compared to the winter 2022-23 forecasted peak week beginning January 22, 2023.

Table 4-1: Resource Adequacy Comparison of Winter Forecasts

All values in MW	2023-24	2022-23	Difference
Installed Capacity	164,291	165,548	-1,257
Net Interchange	2,171	2,198	-27
Dispatchable Demand-Side Management	2,475	2,168	307
Total Capacity	**168,937**	**169,914**	**-977**
Demand	112,217	110,639	1,578
Interruptible Load	2,739	2,792	-53
Maintenance/De-rate	22,573	21,032	1,541
Required Reserve	8,885	8,885	0
Unplanned Outages	11,092	11,571	-479
Net Margin	**16,909**	**20,578**	**-3,670**
Week Beginning	January 21, 2024	January 22, 2023	-

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

The Net Margin for the 2023-24 Winter Operating Period has decreased by 3,670 MW from the previous winter (2022-23). This can mainly be attributed to a decrease in the Installed Capacity paired with increases in the forecasted demand and maintenance/de-rate numbers.

The NPCC forecasted capacity outlook indicates a coincident peak Net Margin of 16,909 MW (15.1%) with respect to the 112,217 MW forecasted 50/50 peak demand. When considering 90/10 coincident peak demand, the forecasted 90/10 Net Margin is 11,148 MW (9.4%).

Table 4-2 below summarizes the NPCC forecasted 50/50 load and resource adequacy for the peak week beginning January 21, 2024, 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.

Table 4-2: Resource Adequacy Comparison of 2023-24 Winter Forecast Scenarios

All values in MW	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity	164,291	164,291	164,291
Net Interchange	2,171	2,171	2,171
Dispatchable DSM	2,475	2,475	2,475
Total Capacity	**168,937**	**168,937**	**168,937**
Demand	112,217	117,978	122,203
Interruptible load	2,739	2,739	2,739
Maintenance/De-rate	22,573	22,573	24,328
Required Reserve	8,885	8,885	8,885
Unplanned Outages	11,092	12,122	13,487
Net Margin	16,909	11,148	2,773
Bottled Resources	**0**	**0**	**0**
Revised Net Margin	16,909	**11,148**	**2,773**
Week Beginning	21-Jan-24	21-Jan-24	21-Jan-24
Revised Net Margin %	15.1%	9.4%	2.3%

The following sections detail the 2023-24 winter capacity analysis for each Reliability Coordinator Area.

Maritimes

The Maritimes Area declared Installed Capacity is scheduled to be available for the winter period; the Net Margins calculated include impacting factors such as wind, ambient temperature, and hydro flows that may derate generation and reflect expected out-of-service units. Imports into the Maritimes area are not included unless they have been confirmed as released capacity from their source. Therefore, unless 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 of the Winter Operating Period.

Table 4-3: Maritimes Operable Capacity for Winter 2023-24

Winter 2023-24	Normal Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	7,728	7,728	7,728
Net Interchange (+)	81	81	81
Dispatchable Demand-Side Management (+)	0	0	0
Total Capacity	**7,809**	**7,809**	**7,809**
Interruptible Load (+)	264	264	264
Known Maintenance & Derates (-)	1,106	1,106	1,617
Operating Reserve Requirement (-)	893	893	893
Unplanned Outages (-)	350	350	350
Peak Load Forecast (-)	5,863	6,254	6,435
Net Margin (MW)	**-139**	**-530**	**-1,064**
Net Margin (%)	**-2.4**	**-8.5**	**-19.0**

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 2023-24.

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 to zero, 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 7, 2024 recognizing these factors.

Table 4-4: New England Installed and Operable Capacity for Winter 2023/24

Winter 2023-24 (SCC) – Jan 7	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Operable Capacity + Non-commercial Capacity	31,846	31,846	31,846
Net Interchange (+)	958	958	958
Dispatchable Demand-Side Management (+)	570	570	570
Total Capacity	**33,374**	**33,374**	**33,374**
Peak Load Forecast (-)	20,269	21,032	21,746
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	679	679	1,179
Unplanned Outages and Gas at Risk (-)	6,687	7,617	8,582
Operating Reserve Requirement (-)	2,305	2,305	2,305
Net Margin (MW)	**3,434**	**1,741**	**-438**
Net Margin (%)	**16.9**	**8.3**	**-2.0**

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 2024, 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 25 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 21,746 MW with a net margin of -438 MW (-2.0 percent). This margin assumes 8,582 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. Net Interchange is based on projected capacity transactions external to the New York Control Area (NYCA). 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 NYCA. Beginning November 2015, the NYISO started procuring operating reserve 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.

The NYISO conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 6,480 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 9,068 MW (37.4%) to 2,588 MW (10.7%).

[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.

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 4-7 below presents a conservative scenario comparing the normal, 90/10 and Above 90/10 operating margins for upcoming the winter period.

Table 4-5: New York Operable Capacity Forecast for Winter 2023-24

Winter 2023-24	Normal Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	39,697	39,697	39,697
Net Interchange (+)	1,588	1,588	1,588
Dispatchable Demand-Side Management (+)	802	802	802
Total Capacity	**42,087**	**42,087**	**42,087**
Interruptible Load (+)	1	1	1
Known Maintenance & Derates (-)	4,011	4,011	4,011
Operating Reserve Requirement (-)	2,620	2,620	2,620
Unplanned Outages (-)	2,169	2,169	8,649
Peak Load Forecast	24,220	25,236	27,022
Net Margin (MW)	**9,068**	**8,052**	**-214**
Net Margin (%)	**37.4**	**31.9**	**-0.01**

Ontario

Looking at the 2023-24 Winter Operating Period, considering existing and planned capacity coming in-service, the Ontario reserve requirement is met under both 50/50, 90/10 and Above 90/10 weather conditions, as indicated in **Table 4-8** below.

Table 4-6: Ontario Operable Capacity Forecast for Winter 2023-24

Winter 2023-24	Normal Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity (+)	38,253	38,253	38,253
Net Interchange (+)	17	17	17
Dispatchable Demand-Side Management (+)	853	853	853
Total Capacity	**39,123**	**39,123**	**39,123**
Known Maintenance & Derates (-)	11,963	11,963	11,963
Operating Reserve Requirement (-)	1,567	1,567	1,567
Unplanned Outages (-)	1,068	1,068	1,068
Peak Load Forecast	21,402	22,640	22,909
Net Margin (MW)	**3,123**	**1,868**	**1,600**
Net Margin (%)	**14.6**	**8.3**	**7.0**

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

The above 90/10 case was achieved using a probabilistic weather simulation method. The initial dataset of hourly demand forecasts was created by using 31 years of weather history and utilizing a shifting-iterative methodology. This dataset is then sliced for the weekly peaks at the 90/10 and 99/1 levels of probability. The difference between those forecasts is added to the Extreme weather scenario weekly peaks to approximate an above 90/10 peak.

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 4-9** below indicate that occurrences of unserved energy are not expected over the winter 2023-24 period. Based on these results, it is anticipated that Ontario will be energy adequate for the 50/50 weather scenario for the review period.

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

Month	Forecast Energy Production Capability (GWh)	Forecast Energy Demand (GWh)
Oct 2023	16,155	10,651
Nov 2023	17,431	11,006
Dec 2023	18,761	12,020
Jan 2024	19,106	12,918
Feb 2024	18,040	11,948
Mar 2024	18,267	11,832

Québec

The Québec area anticipates adequate resources to meet demand for the 2023-24 Winter Operating Period. The current 2023-24 peak forecast (50/50) is 40,641 MW and the forecasted operating margin is 598 MW for the area peak week. This includes known maintenance and derates of 4,814 MW, including scheduled generator maintenance and wind generation derating. **Table 4-10** 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 -1,933 MW.

Table 4-8: Québec Operable Capacity Forecasts for Winter 2023-24

Winter 2023-24	50/50 Forecast (MW)	90/10 Forecast (MW)	Above 90/10 Forecast (MW)
Installed Capacity	46,767	46,767	46,767
Net Interchange	-949	-949	-949
Dispatchable Demand-Side Management (+)	250	250	250
Total Capacity	**46,068**	**46,068**	**46,068**
Interruptible Load (+)	2,509	2,509	2,509
Known Maintenance & Derates (-)	4,814	4,814	4,814
Operating Reserve Requirement (-)	1,500	1,500	1,500
Unplanned Outages (-)	1,500	1,500	1,850
Peak Load Forecast	40,641	43,008	43,100
Net Margin	**598**	**-669**	**-1,933**
Net Margin (%)	**1.5**	**-1.6**	**-4.4**

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 350 MW is added to the Unplanned Outages, increasing it from 1,500 MW to 1,850 MW.

If Québec real-time peak demands are higher than forecasted, a number of measures are available to the System Control personnel and are listed in Chapter 6: Operational Readiness.

Québec's energy requirements are met for the greatest part by hydro generating stations located on different river systems and scattered over a large territory. The major plants are backed by multiannual reservoirs (water reserves lasting more than one year). Due to the multi-year reservoirs, a single year of low water inflow cannot adversely impact the reliability of energy supply. However, a series of consecutive dry years may require some operating measures, such as the reduction of exports or capacity purchase from neighbouring areas. To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of two (2) consecutive years of low water inflows totalling 64 TWh, or a sequence of four (4) years totalling 98 TWh and having a 2% probability of occurrence. The use of operating measures and the hydro reservoirs will be managed accordingly. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. Such documents can be found on the Régie de l'Énergie du Québec website.[11]

[11] http://www.regie-energie.qc.ca/audiences/TermElecDistrPlansAppro_Suivis.html

Projected Capacity Analysis by Reliability Coordinator Area

Table 4-11 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.

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

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 21, 2024	164,291	2,171	2,475	168,937	112,217	2,739	22,573	8,885	11,092	16,909
Maritimes	Peak Week	January 14, 2024	7,728	81	0	7,809	5,863	264	1,106	893	350	-139
	Lowest Net Margin	January 14, 2024	7,728	81	0	7,809	5,863	264	1,106	893	350	-139
	NPCC Peak Week	January 21, 2024	7,728	81	0	7,809	5,685	229	1,106	893	350	4
New England	Peak Week	January 21, 2024	31,846	958	570	33,374	20,269	0	679	2,305	6,005	4,116
	Lowest Net Margin	December 10, 2023	31,846	958	570	33,374	19,464	0	3,343	2,305	4,893	3,369
	NPCC Peak Week	January 21, 2024	31,846	958	570	33,374	20,269	0	679	2,305	6,005	4,116
New York	Peak Week	January 21, 2024	39,747	1,588	802	42,137	24,220	1	4,071	2,620	2,169	9,058
	Lowest Net Margin	March 17, 2024	39,797	1,588	802	42,187	23,331	1	5,800	2,620	2,066	8,371
	NPCC Peak Week	January 21, 2024	39,747	1,588	802	43,137	24,220	1	4,071	2,620	2,169	9,058
Ontario	Peak Week	January 21, 2024	38,253	17	853	39,123	21,402	0	11,963	1,567	1,068	3,123
	Lowest Net Margin	January 14, 2024	38,253	17	777	39,047	21,151	0	12,550	1,567	1,014	2,765
	NPCC Peak Week	January 21, 2024	38,253	17	853	39,123	21,402	0	11,963	1,567	1,068	3,123

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
Québec	Peak Week	January 21, 2024	46,767	-473	250	46,544	40,641	2,509	4,814	1,500	1,500	598
	Lowest Net Margin	January 21, 2024	46,767	-473	250	46,544	40,641	2,509	4,814	1,500	1,500	598
	NPCC Peak Week	January 21, 2024	46,767	-473	250	46,544	40,641	2,509	4,814	1,500	1,500	598

Generation Resource Changes through Winter 2023-24

Table 4-12 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.

Table 4-10: Resource Changes from Winter 2022-23 through Winter 2023-24

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/Retirement Date
Maritimes	Shediac Community Solar Farm	1.63	Solar	Q1 - 2023
	Summerside Sunbank	10	BESS	Q4 - 2023
	Northern Maine Solar (Aggregate)	28	Solar	Q4 - 2023
	Milltown Generating Station	-3	Hydro	Q3 - 2023
	PEI Energy Corp Solar Farm	10	Solar	Q3 - 2023
	Net Total	**46.63**		
New England	South Meadow 11-14	-186	Oil	Q2 - 2023
	Springfield Refuse	-10.5	Natural Gas	Q2 - 2023
	Various Hydro	-15.65	Water	Q2 - 2023
	Moore 5	+4.5	Water	Q3 - 2023
	Energy Storage (various)	+49	Storage	Q2-Q3 - 2023
	Solar Projects (various)	+66	Solar	Q1-Q3 - 2023
	Seasonal Adjustments	-484		
	Net Total	**-577**		

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/Retirement Date
New York	Astoria GT Groups 2,3,4	-558	Oil & Gas	Q2 - 2023
	Ravenswood GT 10	-25	Oil & Gas	Q2 - 2023
	74th St GT 1 & 2 (Local Reliability Only)	-37	Oil	Q2 - 2023
	Western NY Wind	-6	Wind	Q4 - 2023
	Ball Hill Wind	100	Wind	Q3 - 2023
	Blue Stonge Wind	124	Wind	Q3 - 2023
	South Fork Wind I&II	136	Wind (Offshore)	Q4 - 2023
	Seasonal ICAP Adjustments	-430		
	Net Total	**-696**		
Ontario	Romney	60	Wind	Q4 - 2023
	Seasonal Adjustments	0		
	Net Total	**60**		-
Québec	**-**	**-**		

Maritimes

Since the 2022-23 Winter Operating Period, there has been a net increase of 46.63 MW of installed capacity in the Maritimes.

The Maritime Link undersea cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides for a 153 MW firm capacity import to Nova Scotia, with an effective load carrying capability (ELCC) of 95%. Due to short-term maintenance outages and the ongoing commissioning work on the HVDC transmission link from Labrador to Newfoundland, a 148 MW coal-fired unit will be retained in Nova Scotia, if needed, to provide firm capacity and maintain an adequate planning reserve margin for reliability.

New England

Since the 2022-2023 Winter assessment period, ISO-NE has retired four oil units (186 MW) as well as a few smaller resources. New generation consists primarily of 49 MW of energy storage and 66 MW solar projects. The seasonal adjustments value of -488 MW reflects an increase in the SCC based on seasonal audit results.

New York

Since the 2022-23 Winter Operating Period, generation capacity in New York has decreased. The retirement of numerous fossil fuel generating units in New York City is partially offset by the addition of wind capacity including New York's first offshore wind facility which is expected to be in-service in Q4, interconnecting into Long Island.

Ontario

By the end of the 2023-24 Winter Operating Period, the total capacity in Ontario is expected to increase by 60 MW.

Québec

The Installed Capacity is estimated at 46,767 MW. [12]

[12] This value may not exactly correspond to the value published in Hydro-Québec's annual report because it was calculated using assumptions that are specific to the current report.

Fuel Infrastructure by Reliability Coordinator Area

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

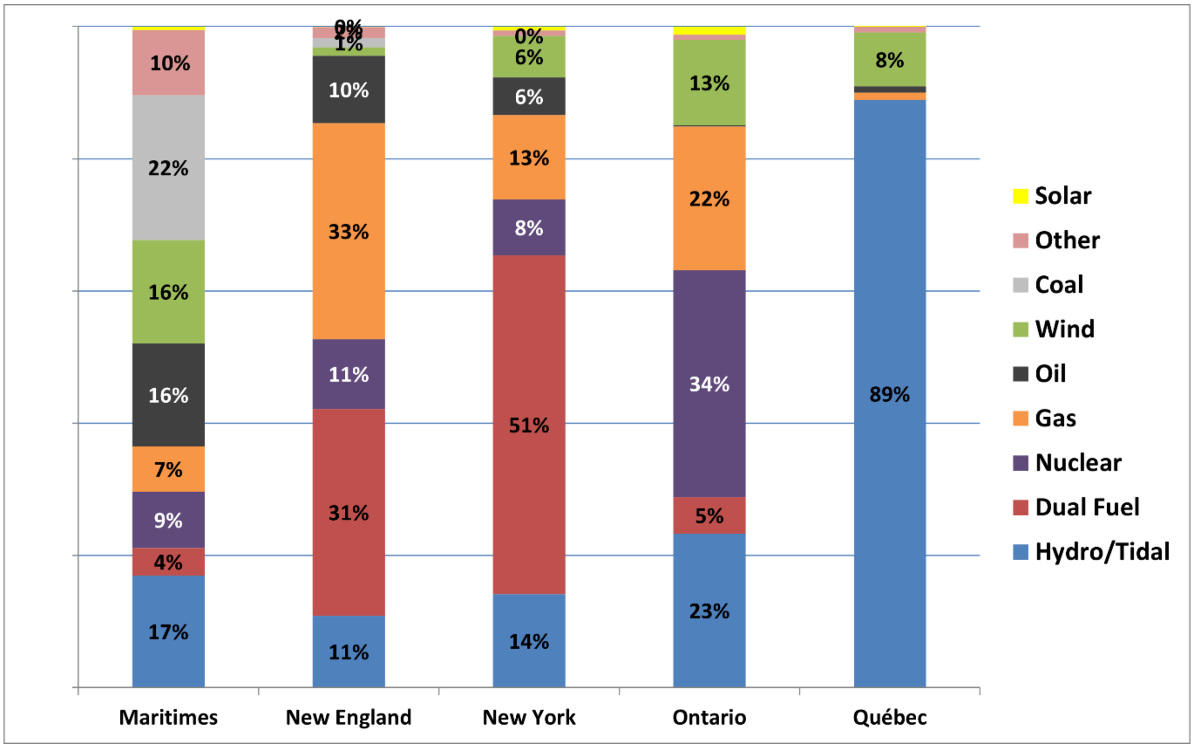


Figure 4-1: Installed Generation Fuel Type by Reliability Coordinator Area

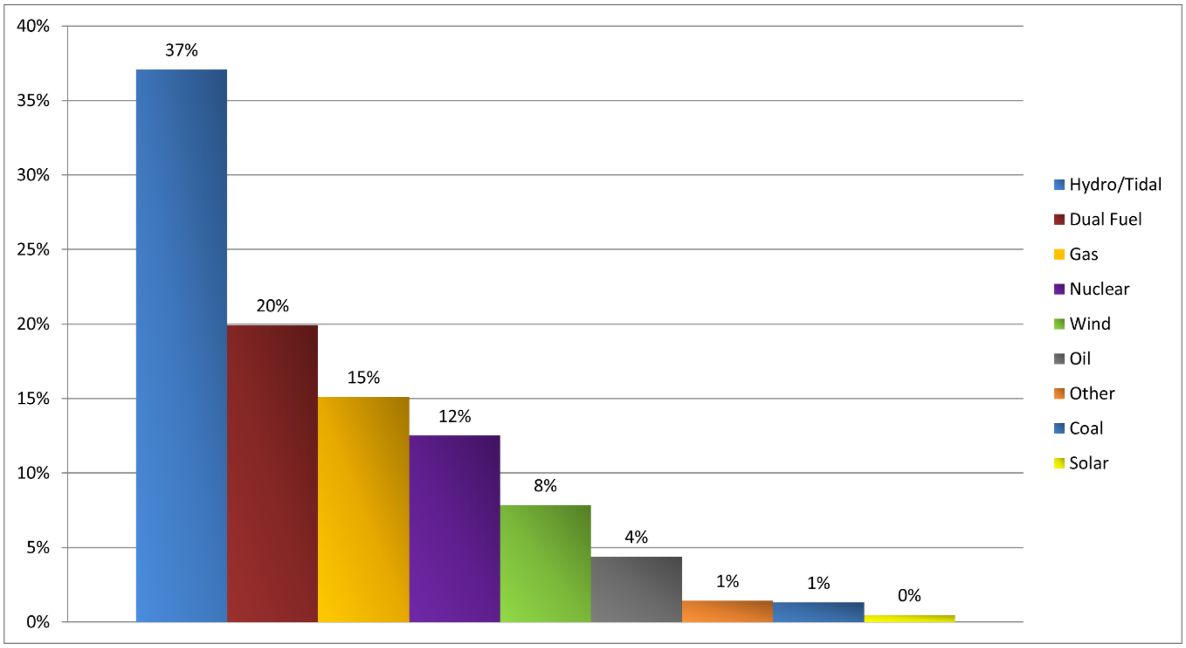


Figure 4-2: Installed Capacity Fuel Profiles for NPCC

Wind and Solar Capacity Analysis by Reliability Coordinator Area

For the upcoming 2023-24 Winter Operating Period, wind, and solar capacity accounts for approximately 8.3% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 7.8% and 0.5% solar. Solar capacity is derated to zero for all areas since it is expected peak load will occur during a time near or after sunset. Reliability Coordinators have distinct methods of accounting for both of these types of generation. The Reliability Coordinators continue to develop their knowledge regarding the operation of wind and solar generation in terms of capacity forecasting and utilization factor.

Table 4-13 below illustrates the nameplate of wind and solar capacity in NPCC for the 2022-23 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 4-14 illustrates behind-the-meter solar PV capacity and the amount of impact it has on peak load demand for each area. The IESO, ISO-NE and NYISO each factor in behind-the-meter solar as a peak load reduction. Methodologies for each area can be found in Appendix IV.

Table 4-11: NPCC Wind and Solar Capacity and Applied Derates

Reliability Coordinator area	Nameplate Wind Capacity Winter (MW)	Wind Capacity After Applied Derating Factor (MW)	Nameplate Offshore Wind Capacity (MW) [13]	Offshore Wind Capacity After Applied Derating Factor (MW)	Nameplate Solar Capacity (MW)	Solar Capacity After Applied Derating Factor (MW)
Maritimes	1,207	261	-	-	42	0
New England	1,546	402	30	15.43	2,718	0
New York*	2,507	741	136	40	224	0
Ontario	4,943	1,972	-	-	478	0
Québec	3,820	1,375	-	-	10	0
Total	**14,023**	**4,751**	**166**	**-**	**3,472**	**0**

**Total wind nameplate capacity in New York is 2,998 MW; however, only 2,507 MW participates in the ICAP market.*

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

Reliability Coordinator area	Installed Behind-the-Meter Solar PV (MW)	Impact of BTM Solar PV on Peak Load (MW)
Maritimes	106	0
New England	3,657	0
New York	5,234	0
Ontario	2,172	0
Québec	27	0
Total	**11,196**	**0**

Maritimes

Wind projected capacity is derated to its demonstrated output for each winter capability period.

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

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

[13] Nameplate Offshore Wind capacity is included in the Total Nameplate Wind capacity.

New Brunswick and Nova Scotia apply a 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 2023-24 winter assessment period, New England derated the 1,546 MW of wind resources by ~74% 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. 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 2023-24 winter season, there is projected to be 2,504 MW of nameplate wind and 224 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 70% 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 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months.

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 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. A dataset comprising ten 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 and natural gas, water, and wind. Contract information is used to estimate both the historical and future output of embedded generation. This information is incorporated into the demand model.

Québec

In the Québec area, wind generation plants are owned and operated by Independent Power Producers (IPPs). Nameplate capacity is 3,820 MW for the 2023-24 winter peak period, de-rated by 64 percent for an expected 1,375 MW contribution. Behind-the-meter installed solar generation is estimated at 27 MW for the upcoming winter period.

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 4-15** 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 21, 2024. Definitions of the terms are included in Appendix II (Load and Capacity Tables definitions).

Table 4-13: Summary of Forecasted Demand Response Programs

Reliability Coordinator Area	DDSM Resources (MW)	Interruptible Loads (MW)	Total (MW)
Maritimes	0	264	264
New England	570	0	570
New York	802	1	803
Ontario	853	0	853
Québec	250	2,509	2,759
Total	**2,475**	**2,739**	**5,214**

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 2023-24 Winter demand response available for NPCC is 5,214 MW, a 254 MW increase from the forecasted 4,960 MW of winter demand response available during 2022-23.

Maritimes

Interruptible loads are forecast on a weekly basis and range between 229 MW and 272 MW. The values can be found in **Table AP-2** and are available for use when corrective action is required within the Area.

New England

In New England, 570 MW of active demand resources are projected to be available on peak for the 2023-24 winter assessment period. In addition to active demand resources, 1,784 MW of passive demand resources (i.e., energy-efficiency measures and conservation) are treated as demand reducers in this report and are accounted for in the load forecast of 20,269 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

The NYISO has three demand response programs to support system reliability. The NYISO currently projects 803 MW of total demand response available for the 2023-24 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 the NYISO with two or more hours' notice, provided the NYISO notifies the Responsible Interface Party a day ahead of the possibility of such a call. In addition, enrolled SCRs are subject to testing each Capability Period to verify their capability to achieve the amount of enrolled load reduction. Failure of an SCR to reduce load during an event or test results in a reduction in the amount of UCAP that can be sold in future periods and could result in penalties assessed to the applicable RIP in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the NYISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, RIPs are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

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

Ontario

Ontario's demand response is comprised of the following programs: Dispatchable loads, 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 642 MW from auctions, 135 MW from dispatchable loads and 76 MW from interruptible loads.

Québec

The Québec Area has various types of Demand Response resources specifically designed for peak shaving during winter operating periods, having an estimated combined impact of 2,759 MW under winter peak conditions (2023-24).

1. The Interruptible load programs are mainly designed for large industrial customers treated as supply-side resources, totaling 1,541 MW for the 2023-24 winter period. Interruptible load 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. 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.
2. The area is also developing some interventions in demand response (e.g., direct control load management and others) to its customers. One of these programs will expand the existing interruptible load program for commercial buildings which has already shown great results. This program has an anticipated impact of 456 MW in 2023-24.
3. New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 270 MW for winter 2023-2024.
4. Data centers specialized in blockchain applications, which are part of new developments in the commercial sector, are required to reduce their demand during peak hours at Hydro-Québec Distribution's request. Their contribution as a resource is expected to be around 242 MW for winter 2023-2024.
5. The voltage reduction program consists of 250 MW that allows the system operator to strategically reduce voltage across designated portions of its distribution system, within regulatory guideline in order to reduce peak demand. This 250 MW is accounted in the "Dispatchable Demand-Side Management" column of the Load and Capacity table presented in **Table AP-6**.

In addition, Energy Efficiency and Conservation programs are implemented throughout the year by Hydro-Québec Distribution 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 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 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 230/345 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.

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:

Table 5-1: Interconnection Total Transfer Capability Summary

Area	Total Transfer Capability (MW)
Transfers from Maritimes to	
Québec	767
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	2,330
Ontario	1,900
PJM	2,965
Québec	1,100
Transfer from Ontario to	
MISO	1,950
New York	2,100
Québec	2,170
Transfers from Québec to	
Maritimes	773 + radial loads
New England	2,275
New York	1,999
Ontario	2,705

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 2023-24 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**.

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

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	-	-	-
New England	Tewksbury STATCOMs	345	Q2 2023
	3136 Line	345	Q4 2023
	Browns River Capacitor Bank	345	Q4 2023
New York	Princetown Station	345	Q2 2023
	Gordon Rd – Princetown 371	345	Q2 2023
	Gordon Rd – New Scotland 361 & 362	345	Q2 2023
	Princetown – New Scotland 55	345	Q2 2023
	Knickerbocker Station	345	Q2 2023
	Knickerbocker-Pleasant Valley Y57	345	Q2 2023
	Van Wagner Station	345	Q2 2023
	Leeds-Hurley Smartwire	345	Q3 2023
	Edic-Princetown 351 & 352	345	Q4 2023
Ontario	Hawthorne TS x Merivale TS Upgrade Conductor	230	Q4 2023
	L34P Phase Angle Regulator (PAR) Replacement	230	Q4 2023
Québec	Micoua – Saguenay line	735	Q4 2023

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

With area generation retirements expected, a 167 MVAR STATCOM will be installed at Tewksbury station to help manage high voltage during light load conditions. Being a dynamic reactive device, Tewksbury STATCOM will support New England's system restoration plan by regulating voltage to allow cable switching as the Boston area transmission system is restored. A new 345kV capacitor bank will be installed at Browns River station which will support voltage in southern New Hampshire. The 3136 line (Woburn to Wakefield Junction) will be installed to bolster Boston's 345kV system. As area generation continues to retire, the 3136 line will provide the thermal support necessary to import transfers into the city. Numerous transmission upgrades continue to be commissioned to address New England's transmission security needs. These transmission improvements have reinforced the overall reliability of the 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

In the coming Winter Operating Period it is expected that the new Edic-Princetown 351 & 352 345kV circuits will come into service as the final part of the Segment A transmission project. The completion of this project will increase the transfer capability of the Central-East interface by about 1,000 MW.

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.

In the eastern part of Ontario, two major 230kV circuits connecting Hawthorne TS and Merivale TS are being upgraded. This will improve the ability to transfer power between eastern Ontario /Quebec interconnection and the other Ontario generation/load centers. The project is expected to be completed Q4 2023.

Following the failure, and then replacement, of the Phase Angle Regulator (PAR) connected to the Ontario-New York 230 kV circuit L33P, the PAR connected to L34P is now also in the process of being replaced. The proposed replacement will provide greater flexibility to control both current and future intertie flows with New York. The expected in-service date of L34P is Q4 2023.

Outages affecting neighboring jurisdictions can be found in **Tables 5-3, 5-4 and 5-5**: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the winter season.

Québec

The Micoua -Saguenay 735 KV transmission line project is expected be in service by the end of this year which would improve the transfer capability of the corridor Manicouagan-Québec beyond its current limit.

Area Transmission Outage Assessment

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

Maritimes

No planned outages to materially impact the transfer capabilities at this time.

New England

Table 5-3: New England Area Transmission Outage Assessment

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New York, Quebec	NY-NE NE-NY HQ-NE	2023/12/05	2023/12/10	NY-NE reduced by up to 1100 MW NE-NY reduced by up to 600 MW HQ-NE reduced by up to 600 MW
New York	NE-NY	2024/01/04	2024/01/05	NE-NY reduced by up to 300 MW
New York	NE-NY	2024/02/13	2024/02/14	NE-NY reduced by up to 300 MW
New York, Quebec	NY-NE NE-NY HQ-NE	2024/02/21	2024/02/22	NY-NE reduced by up to 1100 MW NE-NY reduced by up to 600 MW HQ-NE reduced by up to 600 MW
New York, Quebec	NY-NE NE-NY HQ-NE	2024/03/27	2024/03/28	NY-NE reduced by up to 1100 MW NE-NY reduced by up to 600 MW HQ-NE reduced by up to 600 MW

New York

Table 5-4: New York Area Transmission Outage Assessment

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Quebec	Chateauguay (HQ)-Massena (NY)	2023/11/06	2023/11/27	HQ-NY limited to 0 (-1500 Import) NY-HQ limited to 0 (-1000 Export)
Quebec	Cedars (HQ) – Dennsion (NY)	2023/11/15	2023/11/27	HQ-NY limited to 90 (-189 Import)
Ontario	ONT-NY	2024/03/04	2024/05/24	ONT-NY limited to 1800 (-600 Import) NY-ONT limited to 1350 (-650 Export)
PJM	PJM-NY	2018/01/15	2023/12/31	PJM-NY limited to 2350 (-100 Import) NY-PJM limited to 2050 (-100 Export)

Ontario

Table 5-5: Ontario Area Transmission Outage Assessment

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
NYISO	St. Lawrence PSR34	2022/10/03	2023/11/06	Dependent on dispatch conditions
NYISO	BP76	2024/01/15	2024/01/19	600 MW (Export) / 650 MW (Import)
NYISO	BP76	2024/03/04	2024/05/20	600 MW (Export) / 650 MW (Import)
MISO	J5D	2023/11/13	2023/12/21	450 MW (Export) / 400 MW (Import)
MISO	B3N	2023/12/04	2023/12/08	400 MW (Export) / 450 MW (Import)

Québec

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
DEN	Langlois VFT (forced outage)	2023/09/05	2023/11/16	75 MW
LAW	Line L1291/2	2023/11/15	2023/11/16	65 MW
MASS	Line L7040	2023/11/13	2023/11/27	1800 MW (Export) / 1050 MW (Import)

6. Operational Readiness for Winter 2023-24

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 BPS.

In addition to conducting pre-seasonal reliability assessments, the 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 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 [14] and procedures [15] requiring entities to mitigate the potential effects of geomagnetic disturbances.

As of the writing of this report, preliminary results and recommendations from the FERC, NERC and Regional Entity inquiry into Winter Storm Elliott were released. [16] Once the final report is posted, the Region plans to review and address the recommendations, as appropriate and applicable.

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

[14] See: NERC EOP-010-1, Geomagnetic Disturbance Operations

[15] See: NPCC C-15, Procedures for Geomagnetic Disturbances Which Affect Electric Power Systems

[16] See: Elliott Report: Complete Electricity Standards, Implement Gas Reliability Rules | Federal Energy Regulatory Commission (ferc.gov)

potential set of real-time solutions in the event of a low likelihood, high impact scenario as described in **Section 4**.

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

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	264		243	853	108 – 2,509
Manual Voltage Reduction	N/A	Variable (0 - 375)	–9-611	1.3%/ 0.6%	160 – 250
Curtailment of non-essential Market Participant load	N/A	40	9		
Voluntary curtailment of large LSE customers	N/A	200	15		
Public Appeals	80	300	74	1%	
Additional Actions	N/A	Variable (45 – 2,545), See OP-4 (link)			~1,400
Total Assumption Range	1,055	1,145 – 4,020	1,660 – 2,262		2,418 – 4,909
Lowest Above 90/10 Net Margin Week **Lowest Above 90/10 Net Margin MW |** **With Real-Time Procedures Relief**	**January 14, 2024** **-1,221(-19.0%)** **-184 (-2.9%)**	**January 7, 2024** **-438 (-2%)** **707 (3.3%)**	**January 21, 2024** **-214 (-0.01%)** **2,756 (10.2 %)**	**January 14, 2024** **1,318 (5.8%)** **(N/A)**	**January 21, 2024** **-1,933 (-4.4%)** **(N/A)**

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. Some of these ascertain planning and Emergency Operating mitigations, or Energy Emergency Alerts could be needed under 90/10 peak demand and certain outage scenarios within these procedures include the following:

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

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

Winter Preparation

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

Wind Integration

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

New England

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 2022/23 and ISO 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 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 2023-2024 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 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 allows 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 7-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 2023-2024 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[17].
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[18].
3. Operating Procedure 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[19]. Fuel-supply deficiencies are

[17] ISO New England, Operating Procedure No. 4, *Action During a Capacity Deficiency* (April 27, 2020), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[18] ISO New England, Operating Procedure No. 7, *Action in an Emergency*, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

[19] ISO New England, Operating Procedure No. 21, *Operational Surveys, Energy Forecasting & Reporting and Actions During and Energy Emergency*, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

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.
- 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 20.0% for the 2023-24 winter season.

No unique operational problems were observed from NYISO capability assessment studies. The NYISO maintains Joint Operating Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement, or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas, if required. Prior to the operating month, the NYISO communicates to neighboring control areas both the capacity-backed import and export transactions that are expected for the NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2023-24 winter season, the New York Balancing Authority expects to have 1,588 MW of net import capacity available.

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

NYISO is monitoring the potential for natural gas supplies to electric generators to be affected by natural gas infrastructure maintenance scheduled through the end of December. 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 3,572 MW of resources should the need arise. Reducing Operating Reserves to zero is also an option in extenuating circumstances to avoid load shed.

Energy Storage

Energy storage units are split between transmission system, distribution system, and customer-sited storage. Customer-sited units are considered behind-the-meter, while transmission system and distribution system units are assumed to be part of the wholesale market. Both wholesale and behind-the-meter energy storage units will have relatively small positive net annual electricity consumption due to battery charging and discharging cycles. Only behind-the-meter energy storage units will reduce peak loads when injecting into the grid and only a portion of installed units are expected to be injecting during the NYCA summer and winter peak hours. Wholesale market energy storage does not reduce peak load because it is assumed to be dispatched as generation. Behind-the-meter storage is forecast to reduce peak demand by 234 MW.

Winter Readiness

The NYISO Market Mitigation and Analysis Department performed reviews of several generating stations to discuss past winter operations and preparations for winter 2023-24. Their visits focused on units with low-capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, causes of failed starts, programs to improve performance, and programs in place to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel switching capabilities to improve winter operations.

In the winter of 2013-14, the NYISO instituted a Cold Weather Survey. This survey is sent to all generators and assesses their primary and secondary fuel inventories. This survey is sent prior to the winter season to get baseline numbers and then on a weekly basis. In addition, the survey is sent on days in which extreme temperatures are forecast, in order to enhance real-time situational awareness. The survey allows operators to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day. This procedure will be in place for winter 2023-24.

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.

The NYISO conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 6,480 MW of gas fired generation with non-firm supply are at risk.

The NYISO continues to work on improving gas-electric coordination to enhance reliability and availability of gas fueled units in the future. The NYISO is also considering potential market changes to provide incentives to generators to maintain alternate fuel availability.

Ontario

Base Load

Ontario is entering a period of tighter supply conditions. Surplus baseload generation is not expected to be a significant issue for the foreseeable future.

Voltage Control

Ontario does not foresee any voltage management issues this winter season. However, as high voltage situations arise during periods of light load and under specific outage conditions, the removal of at least one 500 kV circuit may be required to help reduce voltages. Planning procedures are in place to ensure adequate voltage control devices are available during outage conditions when voltage control conditions are more acute. To address high voltage issues on a more permanent basis, two high voltage reactor at Lennox TS were made available in Q3 2023.

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 TransÉnergie'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 peak winter demand. This ensures that the system is designed to carry the resulting transfers while conforming to all design criteria. Resources needed to feed the load during such episodes must be planned and provided by Hydro-Québec Distribution, the Load Serving Entity.

On an operations horizon, if peak demands are higher than expected, a number of measures are available to the System Control personnel. Operating Instruction 33199-I-001 lists such measures:

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

Most of the Québec area hydro generators are located in the north of the province, where 90/10 and above 90/10 cold ambient temperatures often occur during winter periods. Specific Design requirements are implemented to ensure that 90/10 and above 90/10 ambient temperature does not affect operations. In case of any issues that might arise in real time, Maintenance Notices are issued to operators to handle such concerns.

Voltage Control

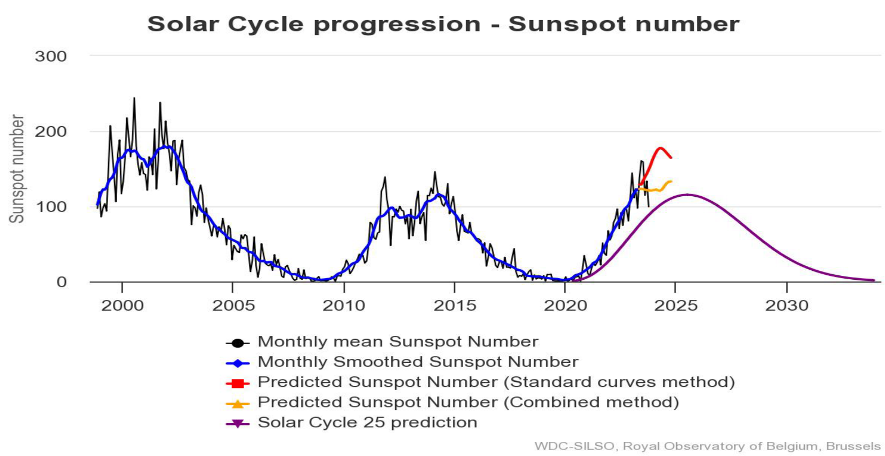
Voltage support in the southern part of the system (load area) might be a concern during Winter Operating Periods, especially during episodes of heavy load. Hydro-Québec Production (the largest producer on the system) ensures that maintenance on generating units is finished by December 1, and that all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

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

Winter 2023-2024 Solar Terrestrial Dispatch[20] Forecast of Geomagnetically Induced Current (GIC)

Solar Activity Forecast Discussion – October 2023

The sun is continuing to exhibit an impressive level of activity. In 2020, the Solar Cycle 25 Prediction Panel, an international group of experts co-sponsored by NASA, NOAA and International Space Environmental Services (ISES), predicted that Solar Cycle 25 would be below-average in sunspot count and similar in size to the last solar cycle. This has not occurred, and long-term forecasts of solar cycles and activities remain challenging.



According to the ISES model of Solar Cycle 25, current GIC activity is far above their model's range of predictions. Other models that have been published in the literature are now being examined to determine if any are better at representing what we are observing. A model created by S.W. McIntosh [21] et al. appears to be among the more accurate. McIntosh predicted that this solar cycle might be among the largest ever observed. Their prediction was a fairly significant outlier when it was published in 2020. The model predicted a sunspot number between 190 and 233 for this solar cycle. And so far, their prediction has been pretty close. If their prediction continues to

[20] See: Solar Terrestrial Dispatch (spacew.com)

[21] See: McIntosh, S.W., Chapman, S., Leamon, R.J. *et al.* Overlapping Magnetic Activity Cycles and the Sunspot Number: Forecasting Sunspot Cycle 25 Amplitude. *Sol Phys* **295**, 163 (2020). https://doi.org/10.1007/s11207-020-01723-y

hold true, it could be larger than any solar cycle we have seen since the late 1980s, or earlier. This has implications for GIC projections.

The plot above shows incidents of major to severe planetary geomagnetic storming (K-indices from 7 to 9) that occurred during each of the prior four solar cycles (in blue). Each dot represents events where GIC activity was possible, if not likely. Red and particularly black dots represent intervals where storming was strong enough to produce potentially serious GIC activity.

According to the chart below, the last solar cycle (24) from 2010 to 2020 was relatively quiet. If the McIntosh prediction of the upcoming solar cycle is accurate, there is an increased likelihood to see many more periods of potential GIC activity similar to what was observed during the first three solar cycles shown in the chart.

Note that the Quebec Blackout occurred in March 1989, [22] which is identified by a black dot. We have not seen geomagnetic activity intense enough to produce a black dot since August 2005 – 18 years ago.

Over the next six months, there will be more than a few days of geomagnetic storming that support minor GIC activity. There is a small, but increasing chance that we could observe a geomagnetic storm large enough to produce moderate to strong GICs in power grids.

Presently, long-term geomagnetic predictions beyond a 3-to-5-day interval are of limited value for operators. The structure of coronal holes changes rapidly and the appearance and evolution of complex sunspot groups makes predictions beyond 3 to 5 days unreliable. Operators are encouraged to review necessary procedures and shorter-term predictions.

[22] See: Boteler, D. H. (2019). A 21st century view of the March 1989 magnetic storm. *Space Weather*, 17, 1427–1441. https://doi.org/10.1029/2019SW002278

7. Post-Seasonal Assessment and Historical Review

Winter 2022-23 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator area's winter 2022-23 operational experiences.

The NPCC coincident peak of 112,552 MW occurred on February 03, 2023 HE19 EST. It was 1,913 MW higher (1.73%) than the forecasted coincident peak of 110,639 MW. This broke the previous all-time NPCC coincident peak set in the summer of 2006 and was spurred on by all-time jurisdictional peaks in both the Maritimes and Québec. Prior to the 2022-2023 Winter Operating Period, the historical NPCC winter peak demand was 111,801 MW on January 2, 2014.

Maritimes

The Maritimes system demand during the NPCC coincident peak was 5,696 MW. Maritimes actual peak was 6,340 MW on February 4, 2023, at HE10 EST. The actual peak demand for the Winter 2022-23 was higher than the historical peak demand of 5,733 MW that occurred during the 2021-22 Winter Operating Period.

All major transmission and interconnections were in service.

New England

The New England system actual peak demand of 19,529 MW occurred on February 3, 2023, at HE19 EST. ISO-NE did need to enact M/LCC 2 and OP 4 on December 24, 2022 due to capacity deficiency.

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 23,369 MW occurred on February 3, 2023 at HE19 EST.

During the 2022-23 Winter Operating Period, the NYISO did not experience transmission or reactive capability issues and was not required to utilize firm load shedding or emergency operating procedures.

Ontario

The actual peak demand was 21,388 MW on February 03, 2023, at HE19 EST. This was higher than the originally forecasted winter peak of 20,984 MW.

There were no significant operational issues observed during the 2022-23 Winter Operating Period.

Québec

During the NPCC coincident peak, the Québec demand was 42,790 MW and the actual peak demand of 42,790 MW occurred on February 3rd, 2023, at HE18 EST. The internal demand forecast was 39,699 MW for the 2022-23 Winter Operating Period. The frigid weather experienced on February 3, 2023 with a bone-chilling temperature of -29.3 degrees Celsius, played a significant role in driving up the demand. This day marked the coldest temperature recorded since 1994 and ranks as the 10th coldest since 1970.

During the peak period on February 3, customers participating in demand response programs were actively engaged to curtail their electricity consumption, resulting in a significant reduction of 2,500 MW. Notably, the predominant share of this consumption reduction was spearheaded by our industrial and commercial clients.

At the time of the Québec peak, exports of 669 MW and imports of 2,453 MW were sustained by the Québec Balancing Authority, for a net exchange of - 1,784 MW.

The actual peak demand for the Winter 2022-23 (42,790 MW) was higher than the historical peak demand of 40,410 MW that occurred during the 2021-22 Winter Operating Period.

Historical Winter Demand Review

Table 7-1 below summarizes historical non-coincident winter peaks for each NPCC Balancing Authority area over the last ten years along with the forecasted 50/50 coincident peak demand for Winter 2022-23. Highlighted values are record demand that occurred during the NPCC Winter Operating Period over the last 10 years.

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

Winter	Maritimes	New England	New York	Ontario	Québec	NPCC Coincident Demand	Date [23]
2012-13	5,431	20,877	24,658	22,610	38,797	111,127	23-Jan-13
2013-14	5,467	21,453	25,738	22,774	39,240	111,801	2-Jan-14
2014-15	5,314	20,583	24,648	21,814	38,950	108,092	8-Jan-15
2015-16	5,237	19,545	23,317	20,836	37,650	102,466	15-Feb-16
2016-17	5,418	19,647	24,164	20,688	37,200	104,335	16-Dec-16
2017-18	5,344	20,631	25,081	20,906	38,410	109,117	5-Jan-18
2018-19	5,265	20,719	24,728	21,525	38,364	109,218	21-Jan-19
2019-20	5,335	18,913	23,253	20,974	36,160	103,969	19-Dec-19
2020-21	5,042	18,756	22,541	20,738	36,677	102,773	16/Dec/20
2021-22	5,733	19,623	23,237	21,349	40,410	109,021	11/Jan/22
2022-23	6,340	19,529	23,369	21,388	42,790	112,552	03/Feb/23

*NPCC Coincident Peak data is unavailable prior to the 2012-13 Winter Operating Period.

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

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

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

[23] Dates of the NPCC Coincident Demand.

8. 2023-24 Winter Reliability Assessments of Adjacent Regions

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

https://rfirst.org/ProgramAreas/ESP/

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 2023-24 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 2023 through March 2024 period. Please refer to Appendix VIII (Table 9) for a description of the Base Case and Severe Case Assumptions.

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 2023/24 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven load levels). The results for the highest peak load levels forecast show the Maritimes and Québec Areas having an increasing likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads). Further, the Maritimes Area shows a risk likelihood of reducing 10-min reserve and the Maritimes, Québec and Ontario have varying reliance on external assistance during the winter 2023/24 period. The highest load level forecast has a combined seven percent chance of occurrence, based exclusively on the two highest of the seven load levels modeled. These results are primarily driven by the Maritimes' and Québec forecast load and corresponding reserve margin expectations.

Under Severe Case conditions, the Maritimes and Québec Areas show an increasing likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads). Once again, the Maritimes Area shows an increased risk likelihood of reducing 10-min reserve and the Maritimes, Québec and Ontario have an increased, varying reliance on external assistance during the winter 2023/24 period. These results are primarily driven by the Maritimes' and Québec forecast load and corresponding reserve margin expectations.

Sensitivity Case

A Sensitivity Case was analyzed using a probabilistic approach based on Severe Resource unavailability and the February 3 - 4, 2023 system conditions [24] repeated through a two week period. The intention of the Sensitivity Case is to assess the ability of the NPCC region to ensure regional reliability and sufficient energy [25] to winter-peaking Areas for the duration of the event under the assumed conditions. Appendix VIII, **Tables 9** and **10** describe the assumptions that

[24] This event represents the time of the NPCC-regional, Maritimes and Québec all-time peak demands.

[25] A zero oil replenishment rate is assumed to assess the inventory levels from the Areas leading into the February 3 – 4, 2023 event.

were used for the Case. Assumptions for this Sensitivity are predicated on the availability of oil-burning resources having an impact on reducing the severity of the event.

The results illustrate that, should the low-likelihood, assumed system conditions occur, the New York, New England, Ontario and Québec Areas show no loss of load for the duration of the event. Assumed resources are sufficient to avoid loss of load for these Areas. Further, the Maritimes and Québec Area's demonstrated a reliance on external assistance to help reduce the need for Emergency Operating Procedures throughout the duration of the event.

Additionally, the results demonstrate an increasing cumulative risk to interrupting Maritimes firm load for the first week of the period, eventually reaching 0.29 days/period LOLE by the end of the period, under the assumed load levels and resource unavailability. Both the Maritimes and Québec Areas demonstrated a reliance on Emergency Operating Procedures (External Assistance, Activation of DR/SCR and Reduction of 30-min Operating Reserve) throughout the two-week period. The Maritimes Area shows a deeper reliance on Emergency Operating Procedures (including Interruptible Loads/Voltage Reduction, Reduction of 10-min Operating Reserve, Appeals and Disconnecting Load) for the two-week event.

Appendix I – Winter 2023-24 50/50 Load and Capacity Forecasts

Table AP-1 - NPCC Summary

Area NPCC
Revision Date November 1, 2023

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 %
26/Nov/23	164,291	700	2,399	167,390	96,236	2,780	30,030	8,885	9,629	39,660	25,389	**26.4%**	25,389	**26.4%**
3/Dec/23	164,291	2,171	2,399	168,861	100,524	2,782	27,550	8,885	9,135	36,686	25,548	**25.4%**	24,468	**24.3%**
10/Dec/23	164,291	2,171	2,399	168,861	103,881	2,770	25,366	8,885	9,942	35,308	23,557	**22.7%**	23,346	**22.5%**
17/Dec/23	164,291	2,171	2,399	168,861	105,904	2,780	24,929	8,885	10,638	35,567	21,285	**20.1%**	21,285	**20.1%**
24/Dec/23	164,291	2,171	2,399	168,861	105,843	2,774	21,786	8,885	11,087	32,873	24,035	**22.7%**	24,035	**22.7%**
31/Dec/23	164,291	2,171	2,399	168,861	107,122	2,746	21,596	8,885	11,725	33,321	22,278	**20.8%**	22,278	**20.8%**
7/Jan/24	164,291	2,171	2,399	168,861	110,045	2,777	21,741	8,885	11,762	33,503	19,205	**17.5%**	19,205	**17.5%**
14/Jan/24	164,291	2,171	2,399	168,861	111,668	2,774	23,089	8,885	11,553	34,642	16,440	**14.7%**	16,440	**14.7%**
21/Jan/24	164,291	2,171	2,475	168,937	112,217	2,739	22,573	8,885	11,092	33,666	16,909	**15.1%**	16,909	**15.1%**
28/Jan/24	164,291	2,171	2,399	168,861	111,188	2,744	22,458	8,719	10,869	33,328	18,370	**16.5%**	18,370	**16.5%**
4/Feb/24	164,291	2,171	2,475	168,937	109,128	2,777	22,726	8,719	11,038	33,764	20,103	**18.4%**	20,103	**18.4%**
11/Feb/24	164,291	2,171	2,399	168,861	107,812	2,767	22,282	8,719	10,633	32,916	22,182	**20.6%**	22,182	**20.6%**
18/Feb/24	164,291	2,171	2,399	168,861	106,348	2,770	23,369	8,719	9,902	33,271	23,293	**21.9%**	23,293	**21.9%**
25/Feb/24	164,341	2,171	2,399	168,911	104,157	2,775	23,919	8,719	9,491	33,410	25,399	**24.4%**	25,399	**24.4%**
3/Mar/24	164,341	2,171	2,399	168,911	102,209	2,764	25,427	8,719	7,308	32,735	28,013	**27.4%**	28,013	**27.4%**
10/Mar/24	164,341	2,171	2,399	168,911	100,352	2,765	28,300	8,719	7,280	35,580	27,024	**26.9%**	27,024	**26.9%**
17/Mar/24	164,341	2,171	2,399	168,911	96,135	2,771	29,435	8,719	7,194	36,629	30,199	**31.4%**	29,205	**30.4%**
24/Mar/24	164,341	2,171	2,399	168,911	93,049	2,772	29,587	8,719	7,143	36,730	33,185	**35.7%**	30,498	**32.8%**

Key
Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand and minimum Revised Net Margin.
Highlighted week beginning 24-Mar-24 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 November 1, 2023

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Interruptible Load MW	Known Maint./Derat. MW [1]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
26/Nov/23	7,728	81	0	7,809	4,996	270	1,415	893	350	424	**8.5%**
3/Dec/23	7,728	81	0	7,809	5,101	272	1,272	893	350	464	**9.1%**
10/Dec/23	7,728	81	0	7,809	5,312	260	1,123	893	350	390	**7.3%**
17/Dec/23	7,728	81	0	7,809	5,420	270	1,119	893	350	296	**5.5%**
24/Dec/23	7,728	81	0	7,809	5,294	264	1,018	893	350	518	**9.8%**
31/Dec/23	7,728	81	0	7,809	5,474	236	1,018	893	350	310	**5.7%**
7/Jan/24	7,728	81	0	7,809	5,603	267	1,106	893	350	124	**2.2%**
14/Jan/24	7,728	81	0	7,809	5,863	264	1,106	893	350	-139	**-2.4%**
21/Jan/24	7,728	81	0	7,809	5,685	229	1,106	893	350	4	**0.1%**
28/Jan/24	7,728	81	0	7,809	5,745	234	1,099	893	350	-44	**-0.8%**
4/Feb/24	7,728	81	0	7,809	5,750	267	1,099	893	350	-16	**-0.3%**
11/Feb/24	7,728	81	0	7,809	5,524	257	1,099	893	350	199	**3.6%**
18/Feb/24	7,728	81	0	7,809	5,551	260	1,099	893	350	176	**3.2%**
25/Feb/24	7,728	81	0	7,809	5,331	265	1,112	893	350	388	**7.3%**
3/Mar/24	7,728	81	0	7,809	5,237	254	1,110	893	350	473	**9.0%**
10/Mar/24	7,728	81	0	7,809	4,813	255	1,110	893	350	897	**18.6%**
17/Mar/24	7,728	81	0	7,809	4,636	261	1,143	893	350	1,048	**22.6%**
24/Mar/24	7,728	81	0	7,809	4,403	262	1,517	893	350	907	**20.6%**

Key

Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 24-Mar-24 denotes week with the largest forecasted NPCC "Revised Net Margin".

Highlighted number denotes forecasted Winter 2023-24 Peak Load for Maritimes.

Notes

(1) Known Maint./Derate include wind.

(2) Week beginning 14-Jan-24 denotes the forecasted Maritimes Winter 2023-24 Peak Week.

Table AP-3 – New England

Area ISO-NE
Revision Date October 23, 2023

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]	Interruptible Load MW [4]	Known Maint./Derat. MW [5]	Req. Operating Reserve MW [6]	Unplanned Outages MW [7]	Net Margin MW	Net Margin %
26/Nov/23	31,846	958	570	33,374	18,794	0	3,995	2,305	4,521	3,759	**20.0%**
3/Dec/23	31,846	958	570	33,374	19,177	0	3,331	2,305	4,254	4,307	**22.5%**
10/Dec/23	31,846	958	570	33,374	19,464	0	3,343	2,305	4,893	3,369	**17.3%**
17/Dec/23	31,846	958	570	33,374	19,475	0	2,678	2,305	5,444	3,472	**17.8%**
24/Dec/23	31,846	958	570	33,374	19,537	0	886	2,305	6,198	4,448	**22.8%**
31/Dec/23	31,846	958	570	33,374	19,808	0	679	2,305	6,692	3,890	**19.6%**
7/Jan/24	31,846	958	570	33,374	20,269	0	679	2,305	6,687	3,434	**16.9%**
14/Jan/24	31,846	958	570	33,374	20,269	0	679	2,305	6,520	3,601	**17.8%**
21/Jan/24	31,846	958	570	33,374	20,269	0	679	2,305	6,005	4,116	**20.3%**
28/Jan/24	31,846	958	570	33,374	20,049	0	738	2,305	5,662	4,620	**23.0%**
4/Feb/24	31,846	958	570	33,374	19,784	0	402	2,305	5,618	5,265	**26.6%**
11/Feb/24	31,846	958	570	33,374	19,755	0	402	2,305	5,275	5,637	**28.5%**
18/Feb/24	31,846	958	570	33,374	19,495	0	343	2,305	4,760	6,471	**33.2%**
25/Feb/24	31,846	958	570	33,374	18,516	0	400	2,305	4,417	7,736	**41.8%**
3/Mar/24	31,846	958	570	33,374	18,170	0	469	2,305	2,296	10,134	**55.8%**
10/Mar/24	31,846	958	570	33,374	17,976	0	2,304	2,305	2,200	8,589	**47.8%**
17/Mar/24	31,846	958	570	33,374	17,614	0	2,406	2,305	2,200	8,849	**50.2%**
24/Mar/24	31,846	958	570	33,374	17,054	0	2,702	2,305	2,200	9,113	**53.4%**

Key

Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 24-Mar-24 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted numbers denote forecasted Winter 2023-24 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 2023-2024 capacity commitment period.
(2) Net Interchange includes peak purchases / sales from Maritimes, Quebec, and New York.
(3) Preliminary load forecast assumes net Peak Load Exposure (PLE) of 20,269 MW and does include 1,784 MW credit for Energy Efficiency (EE) and 0 MW of behind-the-meter PV (BTM PV)
(4) On peak, 570 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) 2,305 MW operating reserve assumes 120% of the largest contingency of 1,400 MW and 50% of the second largest contingency of 1,250 MW.
(7) Assumed unplanned outages is based on historical observation of forced outages and any additional reductions for generation at risk due to natural gas supply.
*****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 21,746 MW load @ Dry Bulb Temp = -0.547

Table AP-4 – New York

Area NYISO
Revision Date October 30, 2023

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW [1]	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	Net Margin %
26/Nov/23	39,697	1,588	802	42,087	20,698	1	3,759	2,620	2,184	12,827	**62.0%**
3/Dec/23	39,697	1,588	802	42,087	22,637	1	4,241	2,620	2,155	10,435	**46.1%**
10/Dec/23	39,697	1,588	802	42,087	23,714	1	3,865	2,620	2,177	9,712	**41.0%**
17/Dec/23	39,697	1,588	802	42,087	24,220	1	3,702	2,620	2,187	9,359	**38.6%**
24/Dec/23	39,697	1,588	802	42,087	24,220	1	3,700	2,620	2,188	9,360	**38.6%**
31/Dec/23	39,697	1,588	802	42,087	24,220	1	3,700	2,620	2,188	9,360	**38.6%**
7/Jan/24	39,697	1,588	802	42,087	24,220	1	3,689	2,620	2,188	9,371	**38.7%**
14/Jan/24	39,697	1,588	802	42,087	24,220	1	4,011	2,620	2,169	9,068	**37.4%**
21/Jan/24	39,697	1,588	802	42,087	24,220	1	4,011	2,620	2,169	9,068	**37.4%**
28/Jan/24	39,697	1,588	802	42,087	24,220	1	4,011	2,620	2,169	9,068	**37.4%**
4/Feb/24	39,697	1,588	802	42,087	24,220	1	4,011	2,620	2,169	9,068	**37.4%**
11/Feb/24	39,697	1,588	802	42,087	24,220	1	3,981	2,620	2,170	9,097	**37.6%**
18/Feb/24	39,697	1,588	802	42,087	24,220	1	4,032	2,620	2,167	9,049	**37.4%**
25/Feb/24	39,747	1,588	802	42,137	24,220	1	4,168	2,620	2,162	8,968	**37.0%**
3/Mar/24	39,747	1,588	802	42,137	24,220	1	4,138	2,620	2,164	8,996	**37.1%**
10/Mar/24	39,747	1,588	802	42,137	24,220	1	4,962	2,620	2,114	8,222	**33.9%**
17/Mar/24	39,747	1,588	802	42,137	22,358	1	5,751	2,620	2,066	9,343	**41.8%**
24/Mar/24	39,747	1,588	802	42,137	21,839	1	5,895	2,620	2,057	9,727	**44.5%**

Key

Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 24-Mar-24 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Winter 2023-24 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
(2) Week beginning 21-Jan-24 denotes the New York Peak Week

Table AP-5 – Ontario

Area Ontario
Revision Date October 31, 2023

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]	Interruptible Load MW	Known Maint./ Derat./Bottled Cap. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW [4]	Net Margin MW	Net Margin %
26/Nov/23	38,253	17	777	39,047	19,742	0	13,362	1,567	1,074	3,302	**16.7%**
3/Dec/23	38,253	17	777	39,047	20,212	0	13,199	1,567	876	3,193	**15.8%**
10/Dec/23	38,253	17	777	39,047	20,346	0	12,305	1,567	1,022	3,807	**18.7%**
17/Dec/23	38,253	17	777	39,047	20,240	0	13,107	1,567	1,157	2,976	**14.7%**
24/Dec/23	38,253	17	777	39,047	19,407	0	12,206	1,567	851	5,016	**25.8%**
31/Dec/23	38,253	17	777	39,047	20,575	0	11,898	1,567	995	4,012	**19.5%**
7/Jan/24	38,253	17	777	39,047	21,047	0	11,668	1,567	1,037	3,728	**17.7%**
14/Jan/24	38,253	17	777	39,047	21,151	0	12,550	1,567	1,014	2,765	**13.1%**
21/Jan/24	38,253	17	853	39,123	21,402	0	11,963	1,567	1,068	3,123	**14.6%**
28/Jan/24	38,253	17	777	39,047	21,320	0	11,689	1,401	1,188	3,449	**16.2%**
4/Feb/24	38,253	17	853	39,123	20,977	0	11,957	1,401	1,401	3,387	**16.1%**
11/Feb/24	38,253	17	777	39,047	20,543	0	11,409	1,401	1,338	4,356	**21.2%**
18/Feb/24	38,253	17	777	39,047	20,341	0	12,413	1,401	1,125	3,767	**18.5%**
25/Feb/24	38,253	17	777	39,047	20,255	0	12,585	1,401	1,062	3,744	**18.5%**
3/Mar/24	38,253	17	777	39,047	19,618	0	13,879	1,401	998	3,151	**16.1%**
10/Mar/24	38,253	17	777	39,047	19,127	0	13,843	1,401	1,116	3,560	**18.6%**
17/Mar/24	38,253	17	777	39,047	18,572	0	14,052	1,401	1,078	3,944	**21.2%**
24/Mar/24	38,253	17	777	39,047	18,109	0	13,819	1,401	1,036	4,682	**25.9%**

Key

Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 24-Mar-24 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Winter 2023-24 Peak Load for Ontario.

Notes

(1) "Installed Capacity" includes all generation registered in the IESO-administered market.
(2) "Load Forecast" represents the normal weather case, weekly 60-minute peaks.
(3) "Known Maint./Derat./Bottled Cap." includes planned outages, deratings, historic hydroelectric reductions and variable generation reductions.
(4) "Unplanned Outages" is based on the average amount of generation in forced outage for the assessment period.
(5) Week beginning 21-Jan-24 denotes the Ontario Peak Week

Table AP-6 – Québec

Area Québec
Revision Date October 26, 2023

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	Historical Peak Load	Interruptible Load MW	Known Maint./Derat. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
26/Nov/23	46,767	-1,944	250	45,073	32,005		2,509	7,499	1,500	1,500	5,078	**15.9%**
3/Dec/23	46,767	-473	250	46,544	33,397	29,090	2,509	5,507	1,500	1,500	7,149	**21.4%**
10/Dec/23	46,767	-473	250	46,544	35,044	37,200	2,509	4,729	1,500	1,500	6,280	**17.9%**
17/Dec/23	46,767	-473	250	46,544	36,549	38,410	2,509	4,322	1,500	1,500	5,182	**14.2%**
24/Dec/23	46,767	-473	250	46,544	37,385	37,717	2,509	3,975	1,500	1,500	4,693	**12.6%**
31/Dec/23	46,767	-473	250	46,544	37,046	38,950	2,509	4,301	1,500	1,500	4,706	**12.7%**
7/Jan/24	46,767	-473	250	46,544	38,906	35,481	2,509	4,599	1,500	1,500	2,548	**6.5%**
14/Jan/24	46,767	-473	250	46,544	40,166	39,240	2,509	4,743	1,500	1,500	1,145	**2.9%**
21/Jan/24	46,767	-473	250	46,544	40,641	40,410	2,509	4,814	1,500	1,500	598	**1.5%**
28/Jan/24	46,767	-473	250	46,544	39,855	36,667	2,509	4,921	1,500	1,500	1,277	**3.2%**
4/Feb/24	46,767	-473	250	46,544	38,398	42,790	2,509	5,257	1,500	1,500	2,399	**6.2%**
11/Feb/24	46,767	-473	250	46,544	37,769	40,330	2,509	5,391	1,500	1,500	2,892	**7.7%**
18/Feb/24	46,767	-473	250	46,544	36,741	36,380	2,509	5,482	1,500	1,500	3,830	**10.4%**
25/Feb/24	46,767	-473	250	46,544	35,836	35,830	2,509	5,654	1,500	1,500	4,563	**12.7%**
3/Mar/24	46,767	-473	250	46,544	34,964	36,240	2,509	5,831	1,500	1,500	5,259	**15.0%**
10/Mar/24	46,767	-473	250	46,544	34,216		2,509	6,081	1,500	1,500	5,756	**16.8%**
17/Mar/24	46,767	-473	250	46,544	32,956		2,509	6,083	1,500	1,500	7,015	**21.3%**
24/Mar/24	46,767	-473	250	46,544	31,643		2,509	5,654	1,500	1,500	8,756	**27.7%**

Key

Highlighted week beginning 21-Jan-24 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 24-Mar-24 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Winter 2023-24 Peak 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 65% 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.

Appendix II – Load and Capacity Tables definitions

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

Installed Capacity

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

Individual Reliability Coordinator Area particularities

Maritimes

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

New England

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

New York

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

Ontario

This number includes all generation registered with the IESO.

Québec

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

Net Interchange

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

Dispatchable Demand-Side Management

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

Total Capacity

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

Demand Forecast

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

Interruptible Loads

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

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 particularities

Maritimes

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

New England

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

<u>Required Operating Reserve</u>

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

<u>NPCC Glossary of Terms</u>

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

<u>Individual Reliability Coordinator Area particularities</u>

Maritimes

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

New England

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

New York

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

Ontario

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

Québec

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

Unplanned Outages

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

Individual Reliability Coordinator Area particularities

Maritimes

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

New England

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

New York

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

Ontario

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

Québec

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

Net Margin

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

Individual Reliability Coordinator Area particularities

New York

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

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/access.aspx

  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**
  http://reports.ieso.ca/public/TxLimitsAllInService0to34Days/

  http://reports.ieso.ca/public/TxLimitsOutage0to2Days/

  http://reports.ieso.ca/public/TxLimitsOutage3to34Days/
- **Québec**
  http://www.hydroquebec.com/transenergie/en/oasis.html

Transfers from Maritimes to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Québec			
Matapédia, Madawaska	767	767	Eel River winter rating is 350 MW. Madawaska HVDC winter rating is 425 MW.
Total	**767**	**767**	
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.
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**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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.
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	1,900	1,600	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	**1,900**	**1,600**	
PJM			
PJM AC Ties	2,650	2,350	New York applies a 300 MW Transmission Reliability Margin (TRM).
NYC/PJM Linden VFT	315	315	
Total	**2,965**	**2,665**	
Québec			
Chateauguay (QC)/Massena (NY)	1,000	1,000	
Cedars / Québec	100	100	
Total	**1,000**	**1,000**	

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	110	100	The 110 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.
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	470	Capacity from Saunders that can be synchronized to the Hydro-Québec system.
HAW / OUTA Lines A41T, A42T	1,250	1,230	The TRM is 20 MW.
Total	**2,170**	**2,130**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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)	350 + radial loads	350 + radial loads	Eel River HVDC winter rating is 350 MW. Radial load transfer amount is dependent on local loading and is reviewed annually
Madawaska (QC)/Edmundston (NB)	423 + radial loads	423 + radial loads	Madawaska winter rating is 435 MW. When Madawaska converter losses and line losses to the New Brunswick border are taken into account, Madawaska to St-André transfer is 423 MW. Radial load transfer amount is dependent on local loading and is reviewed annually.
Total	**773 + radial loads**	**773 + radial loads**	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 The value estimated at peak load is 1,400 MW.
Bedford (BDF) – Highgate (VT) Line 1429	225	225	Capacity of the Highgate HVDC facility is 225 MW
Stanstead (STS) – Derby (VT) Line 1400	50	50	Normally only 35 MW of load in New England is connected.
Total	**2,275**	**2,275**	
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)	199	199	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.
Total	**1,999**	**1,999**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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.)	410	410	Limitations on the Québec system under peak load conditions restrict deliveries as follows P33C - 345 MW and X2Y – 65 MW. There is no capacity to export to Ontario through Line Q4C.
Outaouais (Qc)/Hawthorne (Ont.)	1,250	1,250	HVDC back-to-back facility at Outaouais.
Total	**2,955**	**2,955**	

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 5.0% and 9.0% (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models. The Maritimes uses 5% 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 New England’s energy model is an annual model of the total energy of the ISO-NE Area, using real income, the real price of electricity, economics, and weather variables as drivers. Income is a proxy for all economic activity.

ISO'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. Monthly models for gross energy and gross demand are developed for the New England region and each of the six New England states. Monthly gross energy models are typically estimated utilizing the last 25 years of monthly energy consumption and weather, along with a variety of economic drivers. Monthly gross energy forecasts result from applying the estimated models to normal monthly weather, based on 25 years of historical weather. Monthly gross peak demand models are estimated utilizing a 15-year rolling window of historical daily peak loads combined with a variety of weather constructs, trend and calendar variables, and monthly energy consumption. Monthly gross peak demand forecasts are then generated by applying the estimated models to weekly weather distributions, based on 25 years of historical weather. "50/50", "90/10", and "Above 90/10" gross peak demand forecasts result from extracting the 95th, 99th, and 100th percentiles of the distribution, respectively.

Net energy and demand forecasts[26] result from subtracting ISO-NE's energy-efficiency (EE) forecast and solar photovoltaic (PV) forecast. Both net and gross forecasts include the expected impacts of electrification as detailed by ISO-NE's transportation and heating electrification forecasts.

The reference summer peak demand forecast, or "50/50", which has a 50% chance of being exceeded, is associated with a WTHI (3-day weighted temperature-humidity index) of approximately 79.9 and CDD (cooling degree days, base 65°F) of 16.9. The 90/10 summer peak demand forecast which has a 10% chance of being exceeded, is associated with a WTHI of 81.6 and CDD of 20.0.

The reference winter peak demand forecast, or "50/50", is associated with an effective temperature (which includes the effect of both dry-bulb temperature and wind speed) of 6.0 and HDD (heating degree days, base 65 °F) of 56.6. The 90/10 winter peak demand forecast is associated with an effective temperature of -2.8 and HDD of 61.5. The Above 90/10 winter peak demand forecast is associated with an effective temperature of -11.88 and HDD of 64.9. [27]

From a short-term load forecast perspective, New England utilizes a Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability on a zonal level by taking into account conflicting weather patterns, for example, when the Boston zone is forecasted to be five degrees while the Hartford area is forecast to be thirty degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The loads for the eight

[26] Additional information describing ISO New England's load forecasting may be found at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

[27] Further information describing ISO New England's load forecasting methodologies is available at http://www.iso-ne.com/system-planning/system-forecasting/load-forecast .

zones are then summed to estimate a total New England load, adding an additional New England load forecast to its Artificial Neural Network (ANN) models and Similar-Day (SimDay) analyses).

New York

The NYISO conducts load forecasting for the NYCA and for localities within the NYCA. The 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 & 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. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of behind-the-meter 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 the NYISO.

The winter peak forecast is developed by the 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, well below expected temperature winter peak day.

Ontario

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

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

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

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

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

Ontario uses 31 years of history to calculate a weather factor to represent the MW impact on demand if the weather conditions (temperature, wind speed, cloud cover and humidity) are observed in the forecast horizon. Weather is sorted on a monthly basis, and for the 90/10 weather scenario, Ontario uses the maximum value from the sorted history.

The above 90/10 case was achieved using a probabilistic weather simulation method. The initial dataset of hourly demand forecasts was created by using 31 years of weather history and utilizing a shifting-iterative methodology. This dataset is then sliced for the weekly peaks at the 90/10 and 99/1 levels of probability. The difference between those forecasts is added to the Extreme weather scenario weekly peaks to approximate an above 90/10 peak.

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

Québec

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

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

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 47-year temperature database (1971−2017), 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 329 different demand scenarios. Weather uncertainty is calculated from these

329 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.

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

Appendix V - NPCC Operational Criteria and Procedures

NPCC Directories Pertinent to Operations

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

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

- *This document is under triennial review.*

NPCC Regional Reliability Reference Directory #2 – "Emergency Operations"

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

NPCC Regional Reliability Reference Directory #5 – "Reserve"

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

- *This document is under triennial review.*

NPCC Regional Reliability Reference Directory #6 – "Reserve Sharing Groups"

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

NPCC Regional Reliability Reference Directory #8 – "System Restoration"

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

- *This document is under triennial review.*

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

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

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

C-43 "NPCC Operational Review for the Integration of New Facilities"

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

Appendix VI - Web Sites

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.midwestreliability.org

New York ISO

http://www.nyiso.com/

Northeast Power Coordinating Council, Inc.

http://www.npcc.org/

North American Electric Reliability Corporation

http://www.nerc.com

Reliability*First* Corporation

http://www.rfirst.org

Hydro-Québec TransÉnergie

http://www.hydroquebec.com/transenergie/en/

Appendix VII – CP-8 2023-24 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment

For

Winter 2023 - 2024

RCC Approved

December 5, 2023

Conducted by the

NPCC CP-8 Working Group

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The CP-8 Working Group acknowledges the efforts of Mitchel Bringolf, GE Energy Consulting, Michael Lombardi, NPCC, and Patricio Rocha-Garrido, the PJM Interconnection, and thanks them for their assistance in this analysis.

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 2023 through March 2024 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 2023-24*", December 2023, [1] and summarized in **Table 1**.

Table 1: Assumed Load and Base Case Capacity for Winter 2023/24

Area	50/50 Peak [2] (MW)	Higher Peak [3] (MW)	Available Capacity [4] (MW)	Peak Month
Québec (HQ)	40,641	43,779	45,311	January
Maritimes Area (MT)	5,685	6,322	7,790	January
New England (NE)	20,269 [5]	21,027	29,293 [6]	December
New York (NY)	24,481	26,013	39,215	January
Ontario (ON)	21,402	22,997	39,069	January

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

[1] See: https://www.npcc.org/library/reports/seasonal-assessment.

[2] The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.

[3] The higher peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.

[4] 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.

[5] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 22,053 MW; Passive DR = 1,785 MW; BTM PV reduction = 0; Net peak = 20,268 MW.

[6] Total generation = 31,982 MW + Active DR (570 MW) + Net import (628 MW) - Gas at risk (3,887 MW) = 29,293 MW (Net).

of mean demand) and a higher peak load level associated with the second highest peak load level 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 six 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 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 each of the two demand scenarios described above, two different system conditions were considered: Base Case assumptions and Severe Case assumptions. Details regarding the two sets of assumptions are described in **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 2023 – March 2024 period.

The 50/50 peak load results were based on the probability-weighted average of all seven load levels simulated. The highest 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. [7]

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

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Highest Load Level				
Reduce 30-min Reserve	0.328	1.237	-	-	-	3.967	7.348	-	-	-
Initiate Interruptible Loads/Voltage Reduction [8]	0.005	0.577	-	-	-	0.075	3.196	-	-	-
Reduce 10-min Reserve [9]	0.003	0.082	-	-	-	0.052	0.588	-	-	-
Appeals	0.000	0.007	-	-	-	0.006	0.065	-	-	-
Disconnect Load	0.000	0.007	-	-	-	0.006	0.065	-	-	-

[7] Rounded to the nearest whole occurrence, likelihoods of greater than 0.5 days/period are considered as an occurrence.

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

[9] New York initiates Appeals prior to reducing 10-min Reserve.

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 2023/24 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven load levels). 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 for the Maritimes reducing 10-min reserve, as well. These results are primarily 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 2023/24 period.

Table 3 shows the estimated use of demand response programs and operating procedures under the Severe Case assumptions for the expected load level and the highest load level scenarios for the November 2023 – March 2024 period. Occurrences greater than 0.5 days/period are highlighted. [10]

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

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	50/50 Load Level					Highest Load Level				
Reduce 30-min Reserve	1.091	2.588	-	-	-	6.752	13.983	-	-	-
Initiate Interruptible Loads/Voltage Reduction [11]	0.026	0.999	-	-	-	0.393	5.574	-	-	-
Reduce 10-min Reserve [12]	0.021	0.164	-	-	-	0.309	1.166	-	-	-
Appeals	0.007	0.013	-	-	-	0.102	0.132	-	-	-
Disconnect Load	0.007	0.013	-	-	-	0.102	0.132	-	-	-

As shown in **Table 3**, Under Severe Case conditions, the Maritimes and Quebec Areas show a likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and for the Maritimes, initiating interruptible loads) during the 2023/24 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven

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

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

[12] New York initiates Appeals prior to reducing 10-min Reserve.

load levels). For the highest load levels forecast (having approximately a 7% chance of occurring), the Maritimes shows an increased likelihood of using their operating procedures designed to mitigate shortages (reducing 10-min reserve) during the 2023/24 winter period. These results are primarily driven by the Maritimes' forecast load and corresponding reserve margin expectations.

A Sensitivity Case was analyzed using a probabilistic approach based on Severe Resource unavailability and the February 3 - 4, 2023 system conditions [13] repeated through a two week period. The intention of the Sensitivity Case is to assess the ability of the NPCC region to ensure regional reliability and sufficient energy [14] to winter-peaking Areas for the duration of the event under the assumed conditions. **Tables 9** and **10** describe the assumptions that were used for the Case. Assumptions for this Sensitivity are predicated on the availability of oil-burning resources having an impact on reducing the severity of the event.

The results illustrate that, should the low-likelihood, assumed system conditions occur, the New York, New England, Ontario and Québec Areas show no loss of load for the duration of the event. Assumed resources are sufficient to avoid loss of load for these Areas. Further, the Maritimes and Québec Area's demonstrated a reliance on external assistance to help reduce the need for Emergency Operating Procedures throughout the duration of the event.

Additionally, the results demonstrate an increasing cumulative risk to interrupting Maritimes firm load for the first week of the period, eventually reaching 0.29 days/period LOLE by the end of the period, under the assumed load levels and resource unavailability. Both the Maritimes and Québec Areas demonstrated a reliance on Emergency Operating Procedures (External Assistance, Activation of DR/SCR and Reduction of 30-min Operating Reserve) throughout the two-week period. The Maritimes Area shows a deeper reliance on Emergency Operating Procedures (including Interruptible Loads/Voltage Reduction, Reduction of 10-min Operating Reserve, Appeals and Disconnecting Load) for the two-week event.

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[13] This event represents the time of the NPCC-regional, Maritimes and Québec all-time peak demands.

[14] A zero oil replenishment rate is assumed to assess the inventory levels from the Areas leading into the February 3 – 4, 2023 event.

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 2023 through March 2024.

The assumptions used in this probabilistic study are consistent with the NPCC CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter –2023-2024*", December 2023. 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 5.0.2186 was used for this assessment.

3. STUDY ASSUMPTIONS

The database developed by the CP-8 Working Group for the "*NPCC Reliability Assessment for Summer 2023*" [15] was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the winter 2023/24 assessment period.

1. Demand

a. Load Assumptions

Each area provided annual or monthly peak and energy forecasts for winter 2023/24. **Table 4** summarizes each Area's winter 50/50 peak load assumptions for the study period.

Table 4: Assumed NPCC Areas 2023/24 50/50 Winter Peak Demand

Area	Month	Peak Load (MW)
Québec	January	40,461
Maritimes Area	January	5,789
New England	December	20,268 [16]
New York	January	24,481
Ontario	January	22,092

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.

[15] See: https://www.npcc.org/library/reports/seasonal-assessment.

[16] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 22,031 MW; Passive DR = 1785 MW; BTM PV reduction = 0; Net peak = 20,268 MW.

New England

The gross reference (50/50) winter peak forecast is 22,053 MW for the winter of 2023/24. It corresponds to a dry bulb temperature of 7.0°F, which is the 95th percentile of a weekly weather distribution and is consistent with the median of the dry-bulb value at the time of the winter peak over the last 30 years. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected that would be most likely to occur.

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 BA 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 (typically 69 kilovolts or below) according to state-jurisdictional interconnection standards. The 2023 BTM PV forecast can be found using the following link: ISO-NE Final 2023 Photovoltaic (PV) .

Around 6,374 MW (AC nameplate rating) of installed PV resources are expected within New England by the end of 2023; the majority of them (~3,811 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.

ISO-New England also develops a forecast of long-term savings in peak and energy use for the BA area and for each state stemming from state-sponsored Energy-Efficiency (EE) programs. Examples of EE measures include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO-New England's forecast of EE resources is developed with stakeholder input from the Energy-Efficiency Forecast Working Group. Data used to create the EE forecast originates from state-regulated utilities, energy-efficiency program administrators, and state regulatory agencies. The EE forecast is based on averaged production costs, peak-to-energy ratios, and projected budgets of state-sponsored energy-efficiency programs.

The 2023 EE forecast can be found using the following link: eef2023_final_slides.pdf (iso-ne.com). The amount of EE resources is expected to be around 2,022 MW for the 2023-24 winter.

New York

The New York Independent System Operator (New York ISO) employs a multi-stage process in developing load forecasts for each of the eleven zones within the New York Control Area (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 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 GDP, households, population, and commercial and industrial employment. In the second stage, the incremental impacts of behind-the-meter solar PV and distributed generation are deducted from the forecast, and the incremental impacts of electric vehicle usage are added to the forecast. In the final stage, the NYISO aggregates load forecasts by Load Zone (referenced in the rest of this document as "Zone").

These forecasts are based on information obtained from the New York State Department of Public Service (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. [17]

Ontario

The IESO demand forecast includes the impact of conservation, time-of-use rates, and the effects of distributed energy resources.

Québec

The load forecast is consistent with the assumptions used in the "NERC *2023 Long-Term Reliability Assessment*." [18] Québec's demand and energy-sales forecasting is Hydro-Québec Distribution's responsibility. First, the energy-sales forecast is built on the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver

[17] See: c079fc6b-514f-b28d-60e2-256546600214 (nyiso.com)

[18] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

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

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 52-year database of temperatures (1971-2022), adjusted by +0.3 °C (+0.5 °F) per decade starting in 1971 to account for climate change. Moreover, each year of historical climatic data is shifted up to ±9 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 364 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of these 357 scenarios. Load uncertainty is due to the uncertainty in economic and demographic variables affecting demand forecast and to residual errors from the models.

Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty. This Overall Uncertainty, expressed as a percentage of standard deviation over total load, is lower during the summer than during the winter. As an example, at the summer peak, weather conditions uncertainty is about 470 MW, equivalent to one standard deviation. During winter, this uncertainty is 1,790 MW.

b. Load Model in MARS

In previous assessments, the CP-8 Working Group used the historical load shape based on the 2013/14 winter. The selection of the winter hourly load assumption is revaluated on an annual basis with the previous winter load shape.[19] The CP-8 Working Group compared the results of this assessment using the 2022/23 and 2013/14 load shapes and found the 2013/14 load shape to be more stressful on a region-wide basis. The most conservative load shape for the probabilistic assessment may not be the season where the most severe weather was observed.

The loads for each Area were modeled on an hourly, chronological basis, using the 2013/14 hourly load shape. The MARS program modified the hourly loads through time to meet each Area's winter peak demand and energy forecasts.

[19] See: Analysis of the 2022/23 Winter Load Shape (npcc.org)

Figure 1 shows the diversity in the NPCC area monthly 50/50 peak load shapes used in this analysis, with the 2013/14 load shape assumptions.

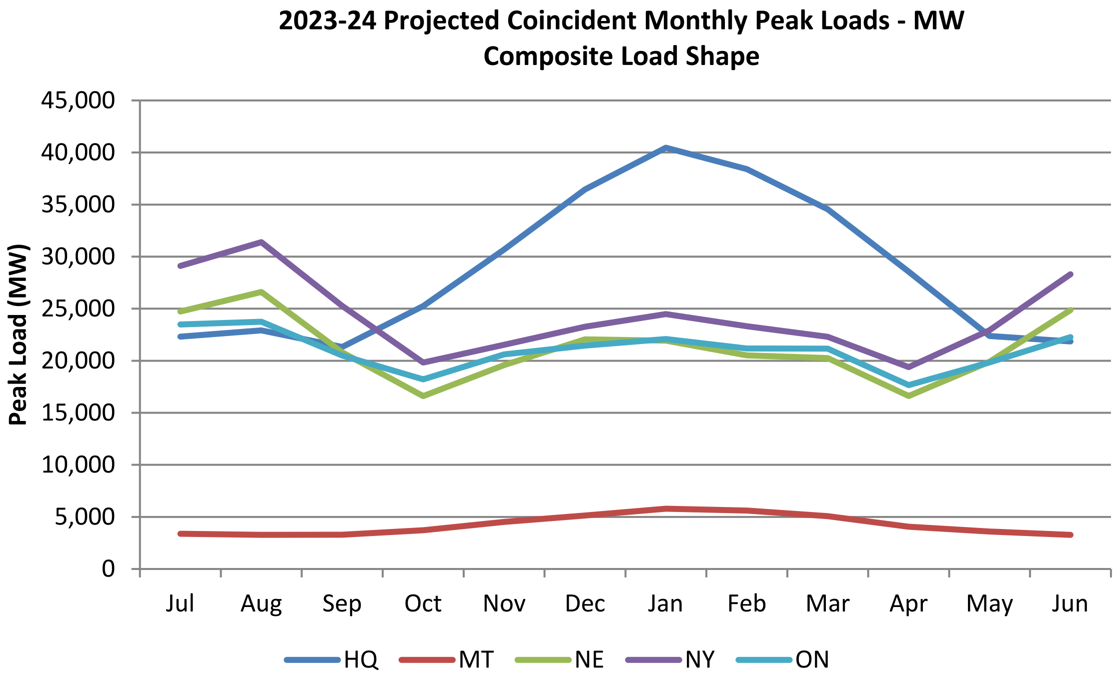

Figure 1: 2023/24 Projected Monthly Peak Loads for NPCC

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*1.058. [20]

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

[20] As highlighted on **Table 5**.

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.

Table 5: Per Unit Variation in Load by Load Level Assumed for the month of January 2024

Area	Per-Unit Variation in Load						
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 7
HQ	1.123	1.082	1.043	1.000	0.958	0.917	0.877
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.100	1.040	0.990	0.946	0.929	0.856	0.800
NY	1.103	1.063	1.026	0.994	0.963	0.935	0.907
ON	1.058	1.041	1.021	1.000	0.976	0.948	0.919
Probability of Occurrence	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

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.

2. Resources

Table 6 below summarizes the winter 2023-24 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 2023-24*", December 2023.

Additional adjustments were made for the Severe Scenario, as explained in **Table 9** of the report.

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

	HQ	MT	NE	NY	ON
Assumed Capacity [21]	45,311	7,790	28,095	39,215	34,069
Demand Response [22]	4,019	253	570	802	853
Net Imports/Exports [23]	-272	-72	628	515	17
Reserve (%)	21.2	37.7	44.5	65.6	58.2
Scheduled Maintenance [24]	-	0	1,513	0	0

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. [25] In addition, the following Areas provided the following:

New England

The generating resources include the existing units and planned resources that are expected to be available for the 2023-24 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.

The resources assumed in this assessment also include the Active Demand Capacity Resources and capacity imports from the neighboring areas. The Active Demand Capacity Resources and imports are based on their Capacity Supply Obligations associated with the 3rd Annual Reconfiguration Auction for Capacity Commitment Period (CCP) of 2022 - 2023. [26]

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*

[21] 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 (4,000 MW).

[22] 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.

[23] 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.

[24] Maintenance scheduled at time of peak.

[25] See: https://www.npcc.org/program-areas/rapa/resource-adequacy.

[26] The 2021-2022 CCP starts on June 1, 2021 and ends on May 31, 2022.

the New York Control Area for the 2023 – 2024 Capability Year – January 13, 2023" [27] and the "*New York Control Area Installed Capacity Requirement for the Period May 2023 to April 2024*" New York State Reliability Council, December 9, 2022 report. [28]

Ontario
Generating unit availability was based on the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2023 to March 2025" (September 21, 2023).* [29]

Québec
The planned resources are consistent with the "*NERC 2023 Long-Term Reliability Assessment*." [30] The planned outages for the winter period are reflected in this assessment. The number of planned outages is consistent with historical values. The MARS modelling details for each type of resource in each Area are provided in Appendix D of the report.

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

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 2023/24 period.

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

New England
The New England transmission system consists of mostly 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

[27] See: https://www.nyiso.com/documents/20142/27428389/LCR2022-Report.pdf/b6dc8eb8-4cde-224d-2b9b-8aa247cac6fc#:~:text=Based%20on%20the%20NYSRC%27s%20final,89.2%25%20for%20the%20G%2DJ%20Locality.

[28] See: http://nysrc.org/PDF/Reports/ICS%20Annual%20Reports/Final%20Final%202022%20IRM%20Study%20Technical%20Report%20Body%2012_10_21%20Clean%2012_13_21.pdf

[29] See: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

[30] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

345 kV ties; one 230 kV tie; one 138 kV tie; three 115 kV ties; one 69 kV tie; and one 330 MW, ±150 kV high-voltage direct-current (HVDC) tie—the Cross-Sound Cable interconnection).

New England and the Maritimes (New Brunswick Power Corporation) are connected through two 345 kV AC ties, the second of which was placed in service in December 2007. New England also has two HVDC interconnections with Québec (Hydro-Québec). One is a 120 kV AC interconnection (Highgate in northern Vermont) with a 225 MW back-to-back converter station, which converts alternating current to direct current and then back to alternating current. The 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).

There are no anticipated transmission additions/upgrades for the upcoming winter.

New York

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

Ontario

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

Québec

The Québec Area is a separate Interconnection from the Eastern Interconnection, into which the other NPCC Areas are interconnected. TransÉnergie, the main Transmission Owner and Operator in Québec, has interconnections 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 are 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 [31], New York [32], and New England [33] are provided in the respective references.

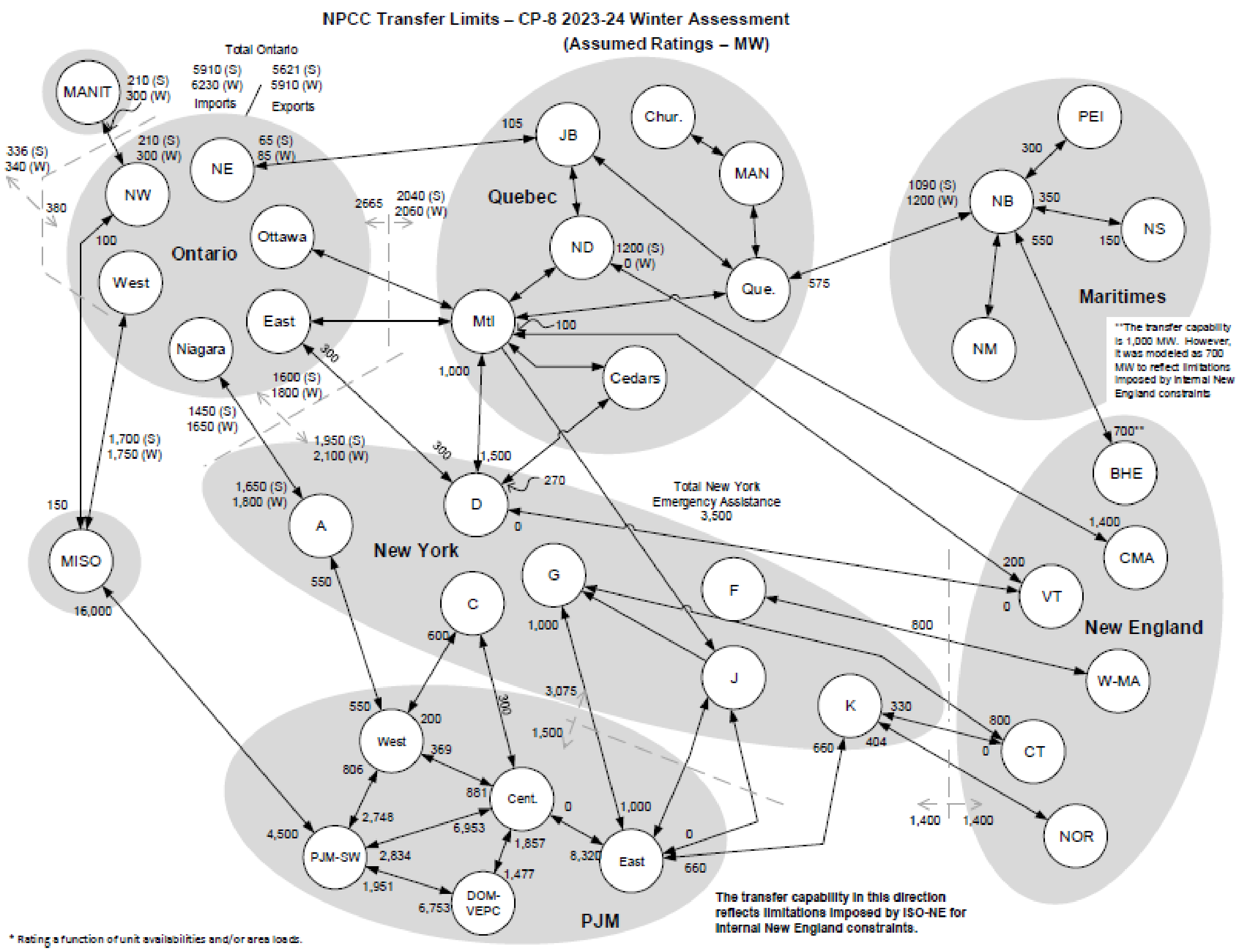

Figure 2: Assumed Transfer Limits

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro-Québec can import up to 100 MW from New York. [34]

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[31] See: http://www.ieso.ca/localContent/ontarioenergymap/index.html.

[32] See: http://nysrc.org/PDF/Reports/ICS%20Annual%20Reports/Final%20Final%202022%20IRM%20Study%20technical%20Report%20Appendices%2012_10_21%20Clean%2012_13_21.pdf.

[33] The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/index.html.

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

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
NM	- Northern Maine	Que Centre	- Québec Centre	Cdrs	- Cedars

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.

Table 7: NPCC Operating Procedures – 2023/24 Winter Load Relief Assumptions (MW)

Actions	HQ	MT	NE	NY [35]	ON
1. Curtail Load Public Appeals RT-DR / SCR SCR Load / Man. Volt. Red.	4,019 - - -	- - - -	- - - -	- - 487 0.3 %	- 1% - -
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction Interruptible Load [36]	250 -	- 253	201 -	1.4% 240	1.3% 853
4. No 10-min Reserves Appeals / Curtailments	750 -	505 -	- -	- 80	945 -
5. 5% Voltage Reduction No 10-min Reserves Appeals / Curtailments	- - -	- - -	- 980 -	- 960 -	0.64% - -

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.

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

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

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.

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**.

Table 8: PJM and MISO 2023/24 Base Case Assumptions [37]

	PJM	MISO
Peak Load (MW)	131,549	75,764
Peak Month	January	January
Assumed Capacity (MW)	179,929	102,687
Purchase/Sale (MW)	-1,756	939
Reserve (%)	39.4	42.8
Weighted Unit Availability (%)	87.7	83.8
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	5,189	4,557
No 30-min Reserves (MW)	2,765	2,670
Voltage Reduction (MW)	2,201	2,200
No 10-min Reserves (MW)	635	1,236
Appeals (MW)	400	400

[37] 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.

Load Forecast Uncertainty (%)	100.0 +/- 14.3, 9.5, 4.8	100.0 +/- 12.0, 8.0, 4.0

Figure 3 shows the winter 2023/24 Projected Monthly 50/50 Peak Loads for NPCC, PJM and MISO for the 2013/14 Load Shape assumption.

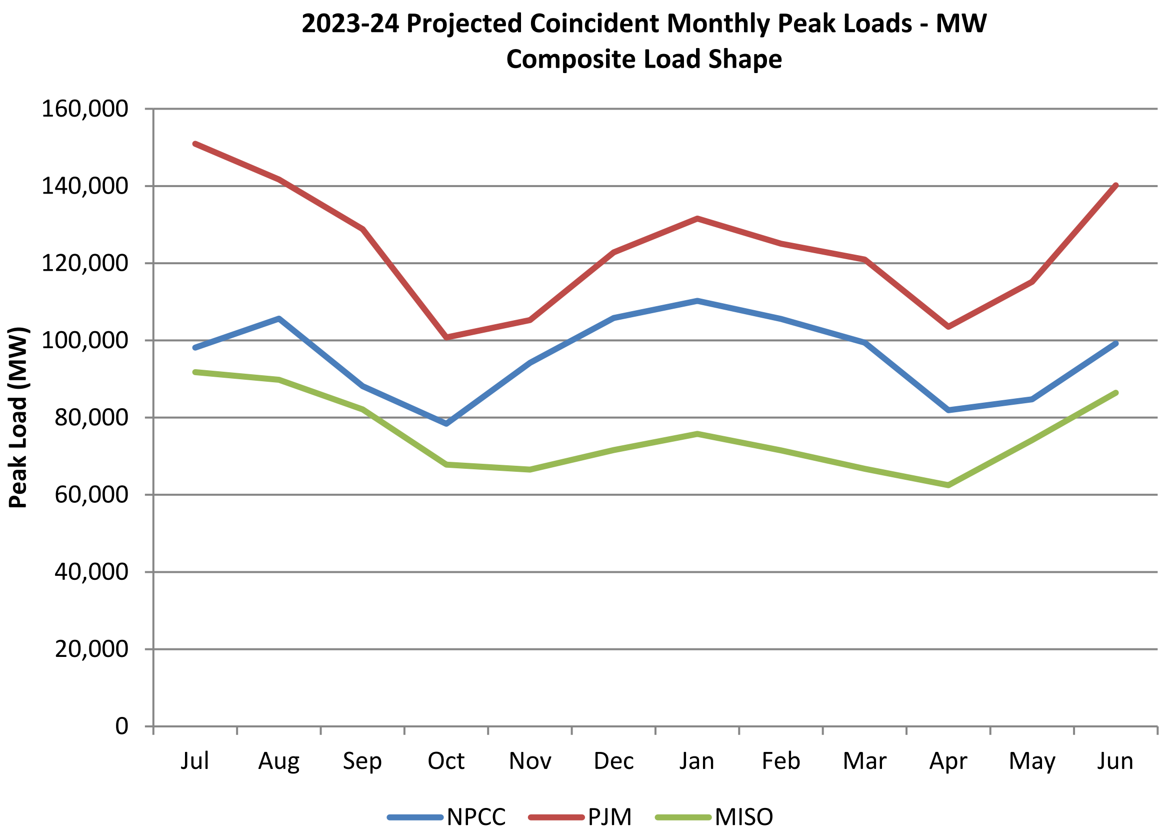

Figure 3: 2023/24 Projected Monthly Winter Peak Loads – 2013/14 Load Shape

Beginning with the "*2015 NPCC Long Range Adequacy Overview*", (LRAO) [38] 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.

[38] See: https://www.npcc.org/content/docs/public/library/resource-adequacy/2016/2015longrangeoverviewrccapproveddecember1.pdf

MISO was modeled in this study due to the strong transmission ties of the region with the rest of the study system.

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. [39] The hourly load shape is based on observed 2013/14 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 2022. [40] Load Forecast Uncertainty was modeled consistent with recent planning PJM models [41] 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 the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's regional Transmission Expansion Plan. [42]

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[39] Please refer to PJM Manuals 19 and 20 at https://www.pjm.com/-/media/documents/manuals/m19.ashx and https://pjm.com/~/media/documents/manuals/m20.ashx for technical specifics.
[40] See: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx
[41] See: https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx#:~:text=The%20PJM%20Reserve%20Requirement%20Study%27s,future%20DY%20are%20also%20derived.
[42] See: https://www.pjm.com/library/reports-notices/rtep-documents.aspx

7. Study Scenarios

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

Table 9: Base and Severe Case Assumptions for NPCC and neighboring Areas

	Base Case Assumptions	Severe Case – Additional Constraints
System	- As-Is System for the 2023-24 period - Transfers allowed between Areas - 2013/24 Load Shapes adjusted to the Area's year 2023 forecast (expected & extreme assumptions)	- As-Is System for the 2023-24 period - Transfers allowed between Areas - Transfer capability between NPCC and MRO/RFC-'Other' reduced by 50%. - 2013/14 Load Shape adjusted to Area's year 2023 forecast (expected & extreme assumptions)
Maritimes	- 1,200 MW of installed wind generation (modeled using 2012-21 calendar hourly wind) - 72 MW export contracts assumed - 253 MW of demand response (interruptible load) available in the Maritimes during the winter period	- Wind capacity is de-rated by half (1,200 MW to 600 MW) for every hour in December, January and February to simulate icing conditions - 50% natural gas capacity curtailment (610 to 305 MW) assumed for winter 2023/24 to simulate a reduction in gas supply for December, January, and February (assuming dual fuel units revert to oil)
New England	Resource and load consistent with the 2023 CELT report data for Winter 2023-2024: - 31,982 MW of existing and planned generation resources modeled - 1,784 MW of energy efficiency resources - 570 MW of Active demand capacity resources - 958 MW of capacity import - 631 MW planned maintenance scheduled - 3887 MW of gas-fired generation at risk due to fuel supply assumed unavailable	- Assume 50% reduction to the import capabilities of external ties - 500 MW of additional maintenance outages assumed from December to February - 4817 MW of gas-fired generation at risk due to fuel supply under severe condition assumed unavailable
New York	- Updated Load Forecast - (NYCA Winter 2023-24 peak load forecast – 24,200 MW; NYC 7,580 MW; LI – 3,255 MW) - Assumptions consistent with New York Installed Capacity Requirements for May 2023 through April 2024 - ~ 569.3 MW of new units activated, ~ 1048.4 MW of units deactivated	- 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 the Ontario Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2023 to March 2025, September 21, 2023 - Demand forecast based on 2013/2014 actual weather	- ~800 MW of maintenance extended into the winter period
Québec	- Resources and load forecast are consistent with the Québec 2023 NERC Long-Term Reliability Assessment - including about 1,900 MW of scheduled maintenance and restrictions - 3,820 MW of installed wind capacity with a 36% peak contribution at winter peak (1,375 MW) - 4,019 MW (ICAP) of demand response - 1,100 MW of available capacity imports -760MW 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 and Neighboring Areas

	Base Case Assumptions	Severe Case Assumptions
PJM-RTO	- As-Is System for the 2023/24 winter period – consistent with the PJM 2023 Reserve Requirement Study [43] - Load Shapes adjusted to the 2022 forecast provided by PJM - Load forecast uncertainty based on PJM 2022 Reserve Requirement Study - Operating Reserve 3,906 MW (30-min. 2, MW; 10-min. 35 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 [44]	- As-Is System for the 2023/24 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)	

A Sensitivity Case (**Table 10**) was also analyzed using a probabilistic approach, for system conditions based on the February 2023 cold snap. Though the event was ~two days, the Sensitivity Case assesses a two-week event and the ability to maintain the LOLE reliability criteria of 0.1 days/year under the assumed conditions. Assumptions for this sensitivity are predicated on the availability of oil burning resources having an impact on reducing the severity of effects of the event.

[43] 2022 PJM Reserve Requirement Study (RRS), dated September 6, 2022 - available at this link on PJM Web site: https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220906/item-04---2022-installed-reserve-margin-study-results.ashx

[44] Does not include the MISO-South (Entergy region).

Table 10: Sensitivity Case Assumptions for NPCC Areas

Sensitivity Case Assumptions	
Load	- Region-wide load shape, peak, load forecast uncertainty are deterministic/locked for the event duration being simulated - Assumes a 2-week event (day-to-day LOL can be extracted from the case for 1 week analysis). - Load profiles based on the 2022/23 Winter Load Shape Analysis
Resource	- Severe Case Assumptions (**Table 9**), with additional assumptions noted below. - Ontario, New England, and New York oil-burning resources are modeled as energy-limited EL3 resources - Actual February 3, 2023 total stored oil in each area is converted to GWh using the average heartrate for oil resources in each respective area. – Area's designated remaining GWh or equivalent, along with additional generating units to be considered as EL3 – Zero oil replenishment rate assumed - The EFORd of oil resources are increased for New England to account for the potential of higher probability of forced outages when these generation resources have been running.

4. STUDY RESULTS

Base Case Scenario

Figure 4 shows the estimated need for the indicated operating procedures in days/period for the November 2023 through March 2024 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**.

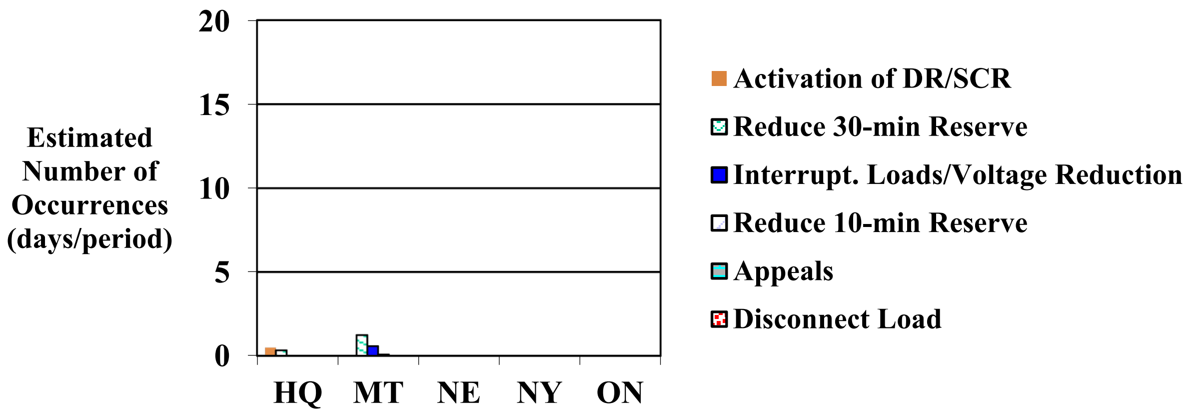

Figure 4: Estimated Use of Operating Procedure for Winter 2023/24
Base Case Assumptions – 50/50 Peak Load Level

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.

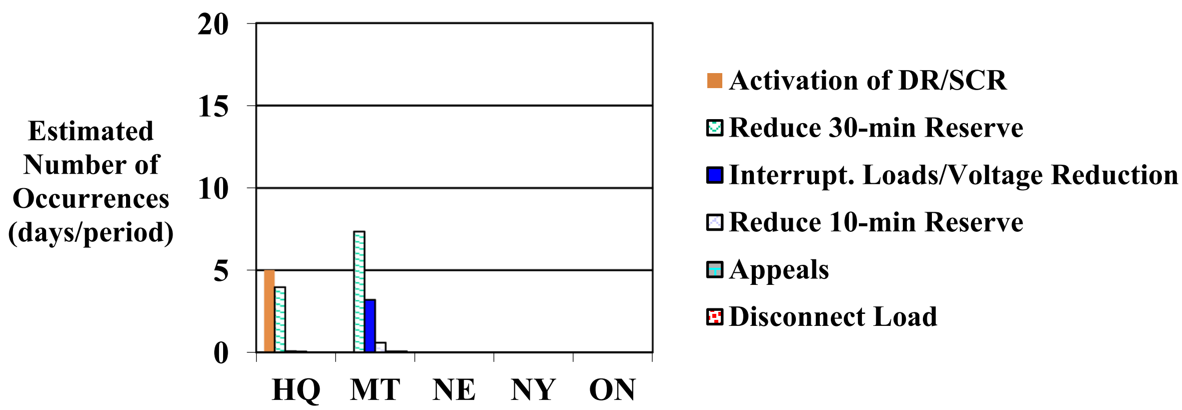

Figure 5: Estimated Use of Operating Procedures for Winter 2023/24
Base Case Assumptions – Highest Peak Load Levels

Severe 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**.

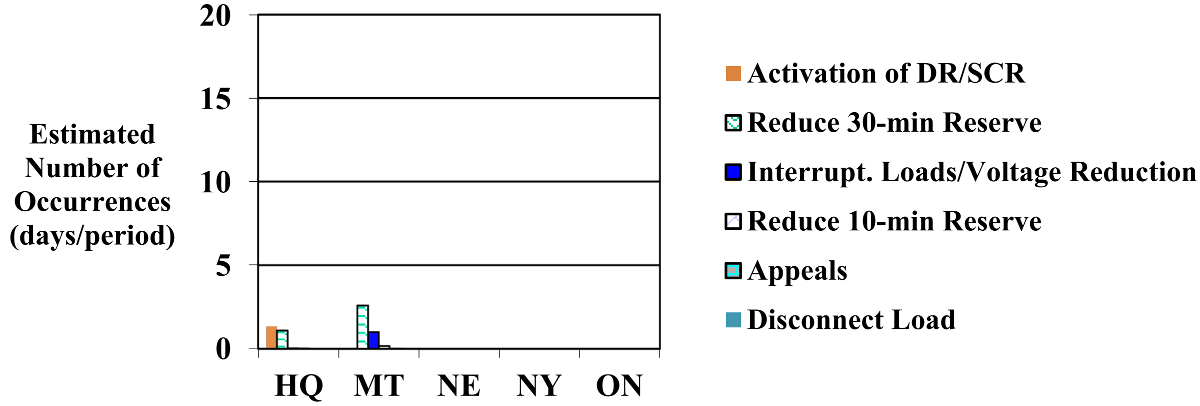

Figure 6: Estimated Use of Operating Procedure for Winter 2023/24 Severe Case Assumptions – 50/50 Peak Load Level

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 seven percent chance of occurring).

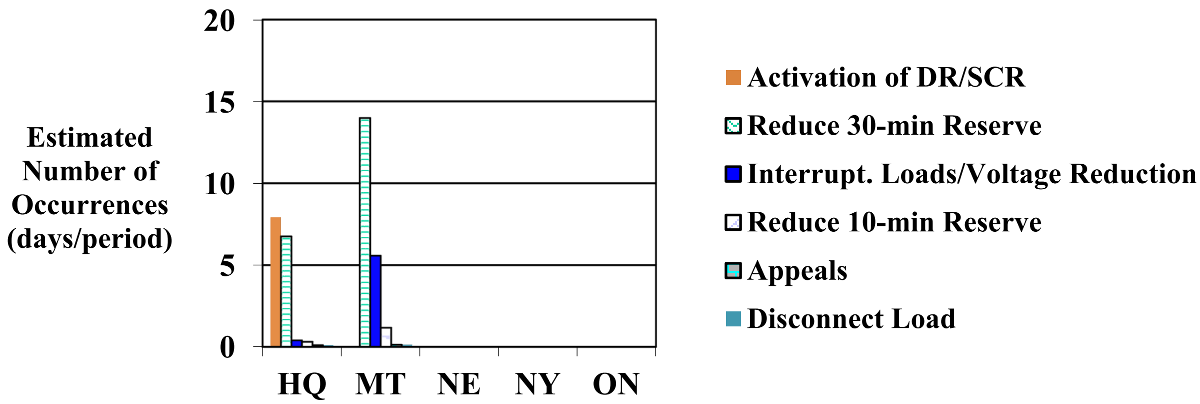

Figure 7: Estimated Use of Operating Procedure for Winter 2023/24 Severe Case Assumptions – Highest Peak Load Level

Sensitivity Case

The results illustrate that, should the low-likelihood, assumed system conditions occur, the New York, New England, Ontario and Québec Areas show no loss of load for the duration of the event. Assumed resources are sufficient to avoid loss of load for these Areas. Further, the Maritimes and Québec Area's demonstrated a reliance on external assistance to help reduce the need for Emergency Operating Procedures throughout the duration of the event.

Additionally, the results demonstrate an increasing cumulative risk to interrupting Maritimes firm load for the first week of the period, eventually reaching 0.29 days/period LOLE by the end of the period, under the assumed load levels and resource unavailability. Both the Maritimes and Québec Areas demonstrated a reliance on Emergency Operating Procedures (External Assistance, Activation of DR/SCR and Reduction of 30-min Operating Reserve) throughout the two-week period. The Maritimes Area shows a deeper reliance on Emergency Operating Procedures (including Interruptible Loads/Voltage Reduction, Reduction of 10-min Operating Reserve, Appeals and Disconnecting Load) for the two-week event.

5. HISTORICAL REVIEW

Table 11 compares NPCC Area's actual 2022/23 winter peak demands against the forecast assumptions.

Table 11: Comparison of NPCC 2022/23 Actual and Forecast Winter Peak Loads [45]

Area	Date	Actual (MW)	Forecast (MW)		Forecast
			50/50 Peak [46]	Higher Peak [47]	Month
Québec	February 3, 2023	42,790	39,853	43,360	January
Maritimes	February 3, 2023	5,696	5,570	6,083	January
New England	February 3, 2023	19,529 [48]	20,009 [49]	20,649	December
New York	February 3, 2023	23,369	23,893	25,539	January
Ontario	February 3, 2023	21,388	21,255	22,128	January

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**.

Operational Review

NPCC

The NPCC Region experienced its all-time peak demand of 112,552 MW on Friday, February 3, 2023 HE 19 EST. The previous all-time peak demand was 112,384 on Tuesday, August 1, 2006.

[45] See: https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2022/npcc-winter-2022-2023-assessment.pdf

[46] The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.

[47] The higher peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.

[48] This is the net peak value – see section 1.2 (footnote 3) of the 2022 CELT forecast: https://www.iso-ne.com/system-planning/system-plans-studies/celt

[49] This is the net peak forecast reflecting the reduction from passive demand response resources and the load reduction impact from the Behind-the-Meter PV. Gross peak = 22,031 MW; Passive DR (EE) = 2,022 MW; BTM PV reduction = 0 MW; Net peak = 20,009 MW. For details, please see 2022 CELT forecast: https://www.iso-ne.com/system-planning/system-plans-studies/celt

Québec

The actual internal winter peak demand of 42,790 MW occurred on Friday, February 3, 2023 at hour ending 18:00 EST, representing the Québec area all-time internal peak demand. At that time, exports of 669 MW and imports of 2,453 MW were sustained by the Québec Balancing Authority, for a net exchange of -1,784 MW.

The previous Québec Area all-time historical internal peak demand of 40,410 MW occurred on Thursday, January 27, 2022 at hour ending 8:00 EST.

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 6,340 MW occurred on Saturday, February 4, 2023 at hour ending 9:30 EST, representing the Maritimes area all-time internal peak demand. The previous Maritimes Area all-time historical internal peak demand of 5,733 MW occurred on Thursday, January 27, 2022 at hour ending 8:00 EST. During the event, both NSPI and New Brunswick declared an EEA-2 alerts after the loss of several resources, and high demands.

New England [50]

The New England average winter temperature departure from normal of +4.8°F was consistent with NOAA's seasonal outlook of above normal temperatures. The 2022/23 New England system peak demand of 19,529 MW occurred on Friday, February 3, 2023 at hour ending 19:00 EST:

- ✓ The New England generation fleet and transmission system performed well overall.
- ✓ LNG supplies were adequate and sendouts were minimal.
- ✓ Fuel oil supplies were adequate; inventories ended the winter ~7M gallons above starting inventories.
- ✓ With the exception of a brief capacity deficiency (OP-4) on December 24, 2022, surplus generating capacity was available throughout the previous winter period; no OP-21 Energy Alert or Energy Emergency actions were implemented last winter.

[50] See COO report: https://www.iso-ne.com/static-assets/documents/2023/05/npc-2023-05-04-coo-rpt-2022-2023-winter-review.pdf

New York [51]

The 2022/23 actual winter peak demand of 23,369 MW occurred on Friday, February 3, 2023, at hour beginning 18:00 EST. This was the second winter season operating without Indian Point Units 2 & 3. Winter 2022-2023 temperatures were above average with the exception of two short duration cold weather events. FERC, NERC, and the regional entities have opened a joint inquiry into operations of the bulk electric system during the storm. [52] New York ISO weekly fuel surveys indicated sufficient alternate fuel inventory. Of note:

- ✓ NYISO met operating criteria throughout the winter
- ✓ No need for emergency actions (voltage reduction, public appeals, etc.); and,
- ✓ The NY Gas System experienced a high number of OFO conditions, including many days not identified as cold weather timeframes in this presentation

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

Ontario [53]

Ontario's peak demand for 2022/23 winter was 21,388 MW on Friday, February 3, 2023 at hour ending 19:00 EST. Electricity demand in Ontario grew by 2.8 per cent in 2022, rising to 137.5 Terawatt hours (TWh) as a result of the province's economic recovery coming out of the pandemic.

There were no significant operational issues observed during the 2022-23 Winter Operating Period.

[51] See: http://nysrc.org/PDF/MeetingMaterial/ECMeetingMaterial/EC%20Agenda%20277/7.3.3%202021%20-%202022%20NYSRC%20EC%20Cold%20Weather%20Operating%20Conditions%20-%20Attachment%207.3.3.pdf

[52] See: https://www.nerc.com/news/Pages/FERC,-NERC-to-Open-Joint-Inquiry-into-Winter-Storm-Elliott.aspx

[53] See: https://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data

6. CONCLUSIONS

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 2023/24 winter period for the 50/50 peak load forecast (representing the probability weighted average of all seven load levels). The results for the highest peak load levels forecast show the Maritimes and Québec Areas having an increasing likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads). Further, the Maritimes Area shows a risk likelihood of reducing 10-min reserve and the Maritimes, Québec and Ontario have varying reliance on external assistance during the winter 2023/24 period. The highest load level forecast has a combined seven percent chance of occurrence, based exclusively on the two highest of the seven load levels modeled. These results are primarily driven by the Maritimes' and Québec forecast load and corresponding reserve margin expectations.

Under Severe Case conditions, the Maritimes and Québec Areas show an increasing likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads). Once again, the Maritimes Area shows an increased risk likelihood of reducing 10-min reserve and the Maritimes, Québec and Ontario have an increased, varying reliance on external assistance during the winter 2023/24 period. These results are primarily driven by the Maritimes' and Québec forecast load and corresponding reserve margin expectations.

The results illustrate that, should the low-likelihood, assumed system conditions occur, the New York, New England, Ontario and Québec Areas show no loss of load for the duration of the event. Assumed resources are sufficient to avoid loss of load for these Areas. Further, the Maritimes and Québec Area's demonstrated a reliance on external assistance to help reduce the need for Emergency Operating Procedures throughout the duration of the event.

Additionally, the results demonstrate an increasing cumulative risk to interrupting Maritimes firm load for the first week of the period, eventually reaching 0.29 days/period LOLE by the end of the period, under the assumed load levels and resource unavailability. Both the Maritimes and Québec Areas demonstrated a reliance on Emergency Operating Procedures (External Assistance, Activation of DR/SCR and Reduction of 30-min Operating Reserve) throughout the two-week period. The Maritimes Area shows a deeper reliance on Emergency Operating Procedures (including Interruptible Loads/Voltage Reduction, Reduction of 10-min Operating Reserve, Appeals and Disconnecting Load) for the two-week event.

APPENDIX A [54]

OBJECTIVE, SCOPE OF WORK AND SCHEDULE

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 2023 - 2024 time 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 2023 - 2024 time 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 2023 summer and November 2023 to March 2024 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;
- 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 (2023– 2024) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages, including

[54] TFCP Approved – January 9, 2023

expected reliability metrics supporting related NERC Reliability Assessment Subcommittee 2023 probabilistic analysis requirements.

Schedule

The NPCC 2023 Summer Probabilistic Multi-Area Reliability Assessment will be approved by the NPCC Task Force on Coordination of Planning no later than by April 21, 2023. A report combining the results of the CP-8 WG Summer Probabilistic Multi-Area Reliability Assessment and the corresponding CO-12 WG Summer Reliability Assessment will be developed.

A report combining the results of the CP-8 WG 2023-2024 Winter Probabilistic Multi-Area Reliability Assessment and the corresponding CO-12 WG 2023-2024 Winter Reliability Assessment will be approved no later than December 5, 2023.

APPENDIX B

DETAILED STUDY RESULTS (days/month)

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

Base Case	Québec				Maritimes Area				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
2013/14 Load Shape - 50/50 Load																						
Nov	-	-	-	-	0.057	0.024	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.015	0.006	0.001	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.323	0.005	0.003	0.000	0.417	0.131	0.043	0.005	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.005	-	-	-	0.310	0.167	0.020	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	0.439	0.250	0.017	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.328	0.005	0.003	0.000	1.237	0.577	0.082	0.007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	0.385	0.173	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.101	0.038	0.009	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	3.889	0.075	0.052	0.006	3.157	0.819	0.299	0.045	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.078	-	-	-	1.750	0.978	0.167	0.011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	1.954	1.187	0.112	0.009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	3.967	0.075	0.052	0.006	7.348	3.196	0.588	0.065	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load. Occurrences 0.5 or greater are highlighted.

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

Severe Case Results	Québec					Maritimes Area					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
2013/14 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	0.057	0.023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	0.042	0.018	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	1.043	0.026	0.021	0.007	0.007	1.250	0.275	0.079	0.008	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.048	-	-	-	-	0.859	0.468	0.068	0.004	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	0.379	0.214	0.014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	1.091	0.026	0.021	0.007	0.007	2.588	0.999	0.164	0.013	0.013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	0.385	0.171	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	0.300	0.145	0.018	0.002	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	6.042	0.393	0.309	0.102	0.102	7.100	1.700	0.592	0.080	0.080	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.710	-	-	-	-	4.489	2.511	0.457	0.042	0.042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	1.708	1.046	0.098	0.008	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	6.752	0.393	0.309	0.102	0.102	13.983	5.574	1.166	0.132	0.132	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
Occurrences 0.5 or greater are highlighted.

APPENDIX C

DETAILED STUDY RESULTS (hours/month)

Table 14: Base Case Assumptions - Expected Need for Indicated Operating Procedures (hours/month)

Base Case																						
	Québec				Maritimes Area				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
2013/14 Load Shape - 50/50 Load																						
Nov	-	-	-	-	0.232	0.088	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.042	0.016	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.660	0.008	0.005	-	1.256	0.383	0.107	0.011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.008	-	-	-	1.493	0.744	0.063	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	2.679	1.415	0.071	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.668	0.008	0.005	-	5.702	2.647	0.244	0.016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	1.695	0.706	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.279	0.108	0.020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	8.840	0.113	0.076	0.006	10.377	2.475	0.724	0.110	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.126	-	-	-	9.367	5.035	0.632	0.023	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	13.126	7.515	0.507	0.030	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	8.966	0.113	0.076	0.006	34.843	15.838	1.886	0.164	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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.

Table 15: Severe Case Scenario - Expected Need for Indicated Operating Procedures (hours/month)

Severe Case Results	Québec					Maritimes Area					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
2013/14 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	0.231	0.088	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	0.123	0.049	0.005	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	2.822	0.074	0.057	0.009	0.009	4.267	0.897	0.199	0.016	0.016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.077	-	-	-	-	4.941	2.541	0.274	0.012	0.012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	2.247	1.177	0.058	0.002	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	2.899	0.074	0.057	0.009	0.009	11.810	4.752	0.536	0.031	0.031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	1.690	0.702	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	0.921	0.391	0.039	0.004	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	27.541	1.109	0.849	0.142	0.142	34.951	6.116	1.593	0.184	0.184	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	1.150	-	-	-	-	28.706	15.813	2.154	0.136	0.136	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	11.088	6.285	0.417	0.024	0.024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	28.691	1.109	0.849	0.142	0.142	77.356	29.308	4.207	0.349	0.349	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

APPENDIX D

DETAILED STUDY RESULTS (MWh/month)

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

Base Case	Québec				Maritimes Area				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
2013/14 Load Shape - 50/50 Load																						
Nov	-	-	-	-	11.4	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	1.6	0.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	12.0	2.4	1.5	0.1	33.4	9.7	1.6	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	99.1	46.8	3.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	199.2	100.5	3.9	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	12.1	2.4	1.5	0.1	344.8	161.6	8.7	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																						
Nov	-	-	-	-	92.7	36.4	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	10.8	4.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	180.1	36.2	22.1	1.8	333.9	85.1	15.1	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.1	-	-	-	699.2	359.1	33.7	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	1089.2	588.6	30.0	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	180.1	36.2	22.1	1.8	2225.6	1073.9	79.5	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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.

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

Severe Case Results	Québec					Maritimes Area					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
2013/14 Load Shape - 50/50 Load																									
Nov	-	-	-	-	-	11.4	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	5.7	2.4	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	118.2	45.1	30.5	6.2	6.2	185.7	46.3	7.6	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	0.1	-	-	-	-	355.3	175.5	15.1	0.5	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	165.8	83.5	3.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	118.3	45.1	30.5	6.2	6.2	723.8	311.6	25.9	0.9	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2013/14 Load Shape – Highest Load Levels																									
Nov	-	-	-	-	-	92.2	36.2	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	44.4	18.4	1.5	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	1757.6	675.2	457.2	92.7	92.7	2082.4	467.4	94.4	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	1.7	-	-	-	-	2306.9	1214.1	137.4	6.1	6.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	908.9	490.5	24.5	1.1	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	1759.3	675.2	457.2	92.7	92.7	5434.8	2226.5	258.0	10.6	10.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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 [55] 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.

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

[55] See: http://ge-energyconsulting.com/practice-area/software-products/mars

analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

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:

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

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

Energy-Limited Units

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

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

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

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

Cogeneration

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

Energy Storage

Energy-storage units are modeled by providing their nameplate capacity and the 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 Comprehensive Review of Resource Adequacy*". [56] In addition, the following Areas provided the following:

New England

The New England generating unit ratings were consistent with their seasonal capability as reported in the 2023 CELT report. [57] 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 2022-2023.

New York

The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the New York ISO Technical Study Report "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2023 – 2024 Capability Year – January 2023*" [58] and the "*New York Control Area Installed Capacity Requirement for the Period May 2023 to April 2024*" New York State Reliability Council, December 9, 2022 report. [59]

Existing Resources

All in-service New York generation resources were modeled. The New York unit ratings were based on the Dependable Maximum Net Capability (DMNC) values from the "*2023 Load & Capacity Data of the NYISO*" (Gold Book). [60]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2023 to March 2025*" *- September 21, 2023.* [61]

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[56] See: https://www.npcc.org/program-areas/rapa/resource-adequacy
[57] See: https://www.iso-ne.com/system-planning/system-plans-studies/celt
[58] See: https://www.nyiso.com/documents/20142/35886565/2023-LCR-Report.pdf/ce034709-ddf4-d53d-6dec-8bd2fd54099f
[59] See: Microsoft Word - 2023 IRM Study Technical Report 12-14-2022 Final - rev 2 (nysrc.org)
[60] See: https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf
[61] See: : Reliability Outlook (ieso.ca)

Québec

The Planned resources are consistent with the "*NERC 2023 Long-Term Reliability Assessment*. [62]

Maritimes

Resources in the Maritimes Area are modeled with winter DMNC ratings.

Resource Availability

New England

This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period (2018 – 2022). 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 2023 – 2024 Capability Year – January 2023*" [63] and the "*New York Control Area Installed Capacity Requirement for the Period May 2023 to April 2024*" New York State Reliability Council, December 9, 2022 report. [64]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2023 to March 2025*", *September 21, 2023.* [65]

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 upon the most recent data from HQ generation and IPPs data. The planned outages for the winter period are reflected in this assessment. The number of planned outages is consistent with historical values.

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[62] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[63] See: https://www.nyiso.com/documents/20142/35886565/2023-LCR-Report.pdf/ce034709-ddf4-d53d-6dec-8bd2fd54099f

[64] See: Microsoft Word - 2023 IRM Study Technical Report 12-14-2022 Final - rev 2 (nysrc.org)

[65] See: : https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

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

Thermal

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

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

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

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

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

Hydro

New England

New England uses the Seasonal Claimed Capability as established through the Claimed Capability Audit to represent the hydro resources. The Seasonal Claimed Capability for intermittent hydro resources is based on their 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 1800 and 1900 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).

Quebec

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

Maritimes

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

Solar

New England

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

New York

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

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

Ontario

Historical hourly profiles are used to model solar generation.

Québec

The 2023-24 winter period contribution of behind-the-meter generation (solar) is estimated at 1 MW (34 MW of ICAP) and doesn't affect the load monitored from a network perspective. Hydro-Québec has commissioned two photovoltaic solar generating stations that have a total installed capacity of 10 MW. As the Québec system is winter peaking, PV impacts at the peak time-period is not significant.

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.

Wind

New England

New England uses the Seasonal Claimed Capability as established through the Claimed Capability Audit to represent the wind resources. The Seasonal Claimed Capability for intermittent wind resources is based on their historical median net real power output during Reliability Hours.

- The Summer Intermittent Reliability Hours shall be hours ending 14:00 through 18:00 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

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

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

Ontario
Historical hourly profiles are used to model wind generation. The model randomly selects a different yearly simulated profile during each iteration.

Québec

or the winter peak period, the contribution of wind units is estimated at The expected capacity at winter peak is 36% of the Installed (Nameplate) capacity. of most wind generation, except for a small amount (roughly 104 MW) which has a 30% capacity at winter peak time. For the summer period, wind power generation is derated by 100%.

Maritimes
Each sub-area within the Maritimes has a series of annual wind shapes corresponding to years from 2012 through 2018. 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.

Demand Response

New England
The passive non-dispatchable energy efficiency resources demand resources are expected to provide ~1,785 MW of load relief during the peak hours. About 570 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. Failure of an SCR to reduce load during an event or test results in a reduction in the amount of UCAP that can be sold in future periods and could

result in penalties assessed to the applicable Responsible Interface Party in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the New York ISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, Responsible Interface Parties are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

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

For this study, 810 MW of SCRs were modeled. At the time of the winter peak, this amount was discounted to 440 MW, based on historical availability.

Ontario

The demand measures are up to 853 MW for the winter period.

Québec

Demand Response (DR) programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs, totaling 4,019 MW for the 2023/24 winter period. The voltage reduction program represents 250 MW of load reduction.

Maritimes

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

APPENDIX G PREVIOUS WINTER REVIEW

Weather

Highlights - (January - March 2023) [66]

The year-to-date (January-March) average contiguous U.S. temperature was 36.3°F, 1.2°F above average, ranking in the middle third of the record.

For the January-March period, the average contiguous U.S. temperature was 37.4°F, 2.3°F above average, ranking 20th warmest in the 129-year record. Temperatures were above average across much of the eastern U.S. with near- to below-average temperatures from the northern Plains to the West Coast. Virginia, North Carolina, South Carolina, Georgia and Florida each had their warmest January-March period on record. New Hampshire, Vermont, Massachusetts, Connecticut, Maryland, Delaware, Ohio, and Alabama each had their second warmest, while 16 additional states ranked among their warmest 10 year-to-date periods on record.

The contiguous U.S. average maximum (daytime) temperature during January-March was 47.9°F, 1.8°F above the 20th century average, ranking in the warmest third of the historical record. Above-average temperatures were observed across much of the eastern contiguous U.S. Near- to below-average temperatures were observed from the northern Plains to the West Coast. Georgia and Florida each ranked warmest on record for daytime temperatures during January-March period. Connecticut, New Jersey, Delaware, Kentucky, and North Carolina each had their second warmest, while 20 additional states ranked among their top-10 warmest January-March on record for daytime temperatures. California ranked ninth coldest while Nevada ranked 10th coldest on record for this three-month period.

Based on the NOAA Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during January-March was 35 percent of average and was the sixth-lowest value on record.

The U.S. Climate Extremes Index (USCEI) for the year-to-date period was 48 percent above average and ranked 12th highest in the 114-year period of record. Extremes in warm maximum temperatures and warm minimum temperatures were the major contributors to this elevated CEI value. 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, the Southeast, South and West ranked above average while the Northeast and Ohio Valley ranked fourth highest for this year-to-date period. The Northeast, Ohio Valley,

[66] NOAA National Centers for Environmental Information, Monthly National Climate Report for March 2023, published online April 2023, retrieved on October 18, 2023 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202303.

Upper Midwest, South and Southeast experienced elevated extremes in warm maximum temperatures and warm minimum temperatures. The Northeast, Upper Midwest and Ohio Valley also experienced elevated extremes in one-day precipitation while the West experienced elevated extremes in cool maximum temperatures and wet PDSI values. Conversely, extremes across the Northwest were 94 percent below average and the Northern Rockies and Plains region was 54 percent below average ranking as their 3rd and 18th lowest year-to-date period on record, respectively.

Northeast Region

December [67]

The Northeast's December average temperature of 30.2 degrees F was 0.4 degrees F warmer than normal. State average temperatures for December ranged from 1.8 degrees F below normal in Maryland to 4.4 degrees F above normal in Maine, with six states wrapping up December on the warm side of normal. This December was among the 20 warmest Decembers for three states: Maine, sixth warmest; New Hampshire, 17th warmest; and Vermont, 18th warmest.

Precipitation during December in the Northeast totaled 4.12 inches, 109 percent of normal. All states except West Virginia saw above-normal precipitation, with amounts ranging from 69 percent of normal in West Virginia to 128 percent of normal in New Hampshire, its 19th wettest December.

The U.S. Drought Monitor from December 6 showed less than 1 percent of the Northeast in severe drought, 2 percent in moderate drought, and 9 percent as abnormally dry. Above-normal precipitation during December alleviated severe drought in northeastern Massachusetts and eased moderate drought in all locations except part of Long Island, New York. Abnormal dryness generally contracted in areas from Maryland to New Hampshire but was introduced or expanded slightly in interior areas such as central New York and northwestern Pennsylvania. Impacts were generally limited to below-normal streamflow and/or groundwater levels. The U.S. Drought Monitor from December 27 showed less than 1 percent of the Northeast in moderate drought and 9 percent as abnormally dry.

A complex storm system brought a mix of precipitation types to the Northeast from December 15 to 17. Higher elevations of northern New York and northern New England accumulated the greatest snowfall totals of 24 inches or more, while ice accumulations of 0.50 inches or more were seen in western Maryland and northern West Virginia. The heavy, wet snow and ice led to multiple accidents and downed tree branches and power lines, with over 60,000 customers in New Hampshire losing power, some for several days. Coastal areas generally saw rain, with the greatest totals around 3 inches. Minor to moderate coastal flooding led to road closures in parts of New

67 NOAA National Centers for Environmental Information, Monthly National Climate Report for December 2022, published online January 2023, retrieved on October 18, 2023 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202212.

Jersey and New York's Long Island. On December 22 and 23, a rapidly-intensifying storm swept through the Northeast, bringing a mix of precipitation types, powerful winds, coastal flooding, and eventually frigid temperatures. On December 22, as a warm front lifted through the region, many areas saw a transition from snow to ice to rain. When the storm's powerful cold front crossed the region on December 23, winds whipped and temperatures plummeted within hours as Arctic air poured in behind the front. For instance, the temperature in Pittsburgh, Pennsylvania, plunged 32 degrees F in three hours, from 40 degrees F at 5 A.M. to 8 degrees F at 8 A.M. More than a dozen major climate sites recorded one of their 10 coldest high temperatures for the month of December on December 24, with highs in the single digits or teens in many locations. The greatest precipitation totals topped 3 inches in parts of Maine, New Hampshire, and southeastern New York. Snowfall was limited to 6 inches or less in most areas; however, unusual ocean-effect snow amounts of up to 7.5 inches were deposited on Martha's Vineyard, Massachusetts. Wind gusts of 30 to 60 mph were common throughout the region, with gusts of 65 mph or greater in parts of New England and western New York. The strong winds removed shingles, peeled back roofs, and downed trees and power lines, which blocked roads and landed on houses and vehicles. In part of Piscataquis County, Maine, more than 300 trees were downed, resulting in extended road closures. Hundreds of thousands of customers across the Northeast lost power, leaving people without heat in frigid temperatures. Wind chills plummeted as low as -45 degrees F, with the lowest readings in eastern West Virginia. Several power companies asked customers to conserve energy as increased usage and intense weather strained grid capacity. Coastal flooding occurred from Maryland to Maine, with water entering houses, submerging roads, and damaging property such as docks. Multiple gauges in New Jersey recorded moderate to major water levels. For instance, preliminary data indicates the gauge at Sandy Hook reached major flood stage at 8.89 feet, its highest recorded stage since Superstorm Sandy in October 2012 and tying as its 10th highest crest (with records back to at least the 1940s). Travel was difficult, with numerous accidents and cancelled or delayed flights, on some of the busiest travel days of the year. The passage of the cold front also triggered a massive lake-effect event that lasted five days, from December 23 to 27, east of Lakes Erie and Ontario in New York. The greatest storm snow totals reached 51.9 inches at the Buffalo Airport in Erie County and 50.8 inches in Jefferson County. Buffalo saw 22.3 inches of snow on December 23, its fourth all-time snowiest day since 1884, with a precipitation amount (rain and liquid equivalent of snow and ice) of 1.98 inches making it the site's wettest December day on record. Buffalo's two-day snowfall total for December 23 to 24 equaled 40.2 inches, its third largest two-day snowfall on record. Wind gusts of 70 mph or higher were recorded in multiple locations in western New York including gusts of 79 mph in Lackawanna and 72 mph at the Buffalo Airport. Blizzard conditions were recorded in Buffalo for around 36 hours, resulting in many hours of zero visibility. Falling trees and frozen substations knocked out power to tens of thousands of customers in Erie County. Travel bans were enacted in Erie and Jefferson counties, and the Buffalo Airport was shut down for several days. Conditions were so intense that hundreds of people became stranded on roads or in unheated homes and required rescuing; however, even first responders got stuck and needed to be rescued. There were at least 41 deaths in Erie County, likely making it one of the deadliest weather events for the county in recent history. This December was Buffalo's third snowiest on record with 64.7 inches of snow. Between November and December, the site accumulated 101.6 inches of snow, more than it typically sees in an entire snow season, 95.4 inches.

January [68]

The Northeast experienced its second warmest January since records began in 1895. The region's average temperature of 33.5 degrees F was 9.4 degrees F warmer than normal. January average temperatures for the 12 Northeast states ranged from 7.6 degrees F above normal in Delaware to 10.5 degrees F above normal in Vermont. This January was the warmest on record for Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont. It ranked as the second warmest on record for New York and Pennsylvania, the third warmest for Delaware and Maryland, and the seventh warmest for West Virginia. January 2023 was the warmest January since record-keeping began for 10 of the Northeast's 35 major climate sites: Newark, New Jersey; Worcester, Massachusetts; Bridgeport, Connecticut; Dulles Airport, Virginia; Allentown, Pennsylvania; Portland, Maine; and Central Park, Islip, Kennedy Airport, LaGuardia Airport, New York. Numerous other temperature records were set throughout the Northeast this January. For more information, see the Notable Weather Events section below.

The U.S. Drought Monitor from January 3 showed less than 1 percent of the Northeast in moderate drought and 9 percent as abnormally dry. Much of the Northeast saw wetter-than-normal weather during January, alleviating abnormal dryness in New England and allowing New Hampshire to be free of drought and dryness for the first time since May 2020. Abnormal dryness also eased in Pennsylvania and northern New Jersey and contracted in New York. However, abnormal dryness was introduced or expanded slightly in areas that were drier than normal during January, including southern New Jersey, southern and western Maryland, and eastern West Virginia. A small area of moderate drought also persisted on Long Island, New York. The U.S. Drought Monitor from January 31 showed less than 1 percent of the Northeast in moderate drought and 3 percent as abnormally dry.

The Northeast was exceptionally warm during January. In addition to several sites experiencing their warmest January on record, several other notable temperature records were set or tied. The average temperature was above normal every day during January for sites such as Philadelphia, Pennsylvania, and Central Park, which were experiencing their longest such streak at 35 days as of January 31. Several sites in New York and New England including Boston, Massachusetts; Providence, Rhode Island; Concord, New Hampshire; and Albany, New York, set/tied their

[68] NOAA National Centers for Environmental Information, Monthly National Climate Report for January 2023, published online February 2023, retrieved on October 18, 2023 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202301.

greatest number of January days with a high of at least 32 degrees F. For instance, the high temperature in Hartford, Connecticut, was at or above freezing every day in January for the first time on record. Similarly, the number of days with low temperatures at or above 20 degrees F tied or set records at multiple sites in New York and New England including Bridgeport, Connecticut; Binghamton, New York; and Burlington, Vermont. In fact, the low temperature in Worcester, Massachusetts, was at least 20 degrees F on 30 days in January, beating the old record of 25 days set in 2002. Similarly, the temperature in Harrisburg, Pennsylvania, remained at or above 26 degrees F this January. All other Januarys back to 1889 at the site have recorded a colder temperature. This milestone of the lowest temperature during January ranking as the warmest on record occurred at 25 of the region's 35 major climate sites. The warm weather allowed some maple syrup producers to tap trees earlier than usual because sap was already flowing; however, soft ground and ice limited access to forests for loggers, delaying projects.

With above-normal temperatures and an unfavorable storm track for heavy snow, most of the Northeast experienced a snowfall deficit in January. In fact, there was no measurable snow during January at Philadelphia, Pennsylvania; Wilmington, Delaware; Baltimore, Maryland; Dulles Airport, Virginia; Washington, D.C.; Newark, New Jersey; Bridgeport, Connecticut; and Islip, LaGuardia Airport, and Kennedy Airport, New York, tying several other years as the least snowy January on record. For Bridgeport it was the first January on record without measurable snow. As of January 31, several of these sites, including Central Park, Kennedy Airport, and Dulles Airport, had not seen measurable snow at all this snow season. For those three sites, the first measurable snow will be the latest on record, more than a month-and-a-half later than usual. The lack of snow affected winter recreation activities such as skiing and snowmobiling, with fewer trails open and a reduction in tourism revenue for businesses; however, transportation departments had a surplus of salt, helping their budgets. The snowy exceptions were parts of New Hampshire and Maine, which saw heavy snowfall during back-to-back-storms from January 22 to 26. The first storm, from January 22 to 23, dropped at least 12 inches of snow in multiple counties in both states, with 17 inches reported in Sullivan County, New Hampshire, and Somerset and Penobscot counties in Maine. The second storm, from January 25 to 26, targeted northern Maine, where up to 18 inches of snow fell. The storm also dropped 12 to 18 inches on portions of Vermont.

February [69]

The Northeast had its fourth warmest February since 1895 with an average temperature of 32.1 degrees F, 5.7 degrees F above normal. Average temperature departures for the 12 Northeast states ranged from 2.5 degrees F above normal in Maine to 7.3 degrees F above normal in West Virginia. This February ranked as the second warmest on record for Maryland, Massachusetts, New Jersey, Pennsylvania, and West Virginia. Meanwhile, Delaware had its third warmest February and Connecticut had its fourth warmest. New Hampshire, New York, Rhode Island, and Vermont had their seventh warmest February, while Maine had its 17th warmest.

On February 16, Islip, New York, and Bridgeport, Connecticut, had their warmest high temperatures for February with highs of 71 degrees F and 68 degrees F, respectively. On the same day, LaGuardia Airport, New York, and Worcester, Massachusetts, tied their warmest low temperatures for February with lows of 54 degrees F and 49 degrees F, respectively. Winter 2022-23 was the warmest winter since recordkeeping began for the Northeast. The region's average temperature of 31.9 degrees F was 5.2 degrees F warmer than normal. State average temperature departures for winter ranged from 4.1 degrees F above normal in Delaware to 6.1 degrees F above normal in Vermont. It was the warmest winter on record for Connecticut, Massachusetts, New Hampshire, and New Jersey. This winter ranked as the second warmest on record for Maine, Maryland, Rhode Island, Vermont, and West Virginia and as the third warmest for Delaware, New York, and Pennsylvania. Two major climate sites experienced their warmest winter on record. The average winter temperature of 41.3 degrees F at Dulles Airport, Virginia, beat the old record of 40.8 degrees F from winter 2016-17. Meanwhile, Worcester, MA, had an average winter temperature of 33.7 degrees F, surpassing the previous record of 33.1 degrees F from winter 2001-02.

The Northeast experienced its seventh driest February since records began in 1895, seeing 1.54 inches of February precipitation, or 56 percent of normal. February precipitation for the 12 Northeast states ranged from 26 percent of normal in Connecticut to 90 percent of normal in West Virginia. This February ranked among the 20 driest Februarys for 11 states: Connecticut, third driest; Rhode Island, fourth driest; New Jersey, fifth driest; Maine and Massachusetts, seventh driest; New Hampshire and Pennsylvania, eighth driest; Delaware, 10th driest; New York, 14th driest; Vermont, 15th driest; and Maryland, 16th driest. The Northeast picked up 10.02 inches of precipitation during winter, which was 102 percent of normal. Winter precipitation for the states ranged from 82 percent of normal in Delaware to 119 percent of normal in Maine and New Hampshire, with seven states wrapping up the season on the wet side of normal. This winter ranked as the 19th wettest for Massachusetts and New Hampshire and as the 20th wettest for Rhode Island.

[69] NOAA National Centers for Environmental Information, Monthly National Climate Report for February 2023, published online March 2023, retrieved on October 18, 2023 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202302.

The U.S. Drought Monitor from January 31 showed less than 1 percent of the Northeast in moderate drought and 3 percent as abnormally dry. During February, moderate drought eased and abnormal dryness contracted on New York's Long Island, while abnormal dryness expanded in eastern West Virginia, western/central Maryland, and southern Pennsylvania. Pockets of abnormal dryness also persisted in central New York, southern New Jersey, and southern Maryland. The U.S. Drought Monitor from February 28 showed 6 percent of the Northeast as abnormally dry. On February 1, up to eight weeks later than usual, several major climate sites including Dulles Airport, Virginia, and Central Park and Kennedy Airport, New York, finally saw their first measurable snow of the season. For those three sites, it was the latest first snow of the season, and for several other sites including Baltimore, Maryland; Philadelphia, Pennsylvania; and Washington, D.C., it was among the five latest. On February 3 and 4, Arctic air briefly made an appearance in the Northeast. Low temperatures dropped into the single digits or below 0 degrees F in multiple locations, with several sites such as Boston, Massachusetts; Providence, Rhode Island; and Kennedy Airport, New York, recording one of their 10 coldest temperatures for February. The National Weather Service in Norton, Massachusetts, noted that Boston's low of -10 degrees F on February 4 was the site's first double-digit below zero day since January 1957. The temperature in Caribou, Maine, remained below zero for nearly 50 consecutive hours. In fact, it was so cold in northern Maine that water in trees expanded and froze, splintering the trees, and there were frost quakes, seismic events caused by sudden cracking of frozen soil or rock due to the freezing and expansion of underground water. Wind gusts of 30 to 55 mph were common, with locally higher gusts of up to 65 mph. The combination of gusty winds and cold temperatures led to below-zero wind chills in multiple areas. For instance, wind chills plummeted to more than -40 degrees F in Portland, Maine, and Burlington, Vermont, and to more than -30 degrees F in Boston, Massachusetts; Hartford, Connecticut; and Albany, New York. Mount Washington, New Hampshire, recorded an unofficial wind chill of -108 degrees F, possibly one of the lowest on record for the U.S. Blizzard warnings were posted for northern Maine, where whiteout conditions and significant drifting of snow left roads impassable. In southern New England, the gusty winds downed trees and power lines, leading to tens of thousands of power outages. As mentioned, the cold air outbreak was short-lived with temperatures climbing by more than 30 degrees F in 24 hours in parts of New York and New England. For example, the temperature in Watertown, New York, went from -32 degrees F at 6 AM on February 4 to 30 degrees F at 6 AM on February 5, a change of 62 degrees F. The warm temperatures continued through mid-month, especially on February 15 and 16 when several major climate sites recorded one of their 10 warmest high and/or low temperatures for February. In fact, on February 16, Islip, New York, and Bridgeport, Connecticut, had their warmest high temperatures for February with highs of 71 degrees F and 68 degrees F, respectively. These high temperatures also ranked among the five warmest for winter at the sites. On the same day, LaGuardia Airport, New York, and Worcester, Massachusetts, tied their warmest low temperatures for February with lows of 54 degrees F and 49 degrees F, respectively. A storm system moved into the Northeast on February 22, bringing portions of Pennsylvania, New York, and New England snow and freezing rain. As the system slid across the region, generally through Pennsylvania and near the New England coast, on February 23, areas to the north saw below- or near-normal temperatures and additional precipitation in various forms.

Storm snowfall totals were 6 inches or less in most areas, with storm ice accumulations from freezing rain reaching 0.50 inches in western New York. Meanwhile, areas to the south in much of Pennsylvania, Maryland, Delaware, and West Virginia saw unusually mild temperatures of 60 to 80 degrees F. The unusually warm temperatures of February and winter contributed to below-normal snowfall for many parts of the Northeast. According to modeled data from the USA National Phenology Network, spring leaf-out arrived earlier than usual in parts of the Mid-Atlantic and coastal Northeast, including Baltimore, Maryland, at nearly three weeks early and New York City at more than a month early.

March [70]

he Northeast wrapped up March with an average temperature of 36.0 degrees F, 1.6 degrees F warmer than normal. Average temperatures for March for the 12 Northeast states ranged from 0.8 degrees F above normal in West Virginia to 3.4 degrees F above normal in Maine, its 17th warmest March since 1895.

March was drier than normal in the Northeast, with the region seeing 2.94 inches of precipitation, 83 percent of normal. March precipitation for the 12 Northeast states ranged from 45 percent of normal in Delaware to 108 percent of normal in Vermont, with eight states being drier than normal, two at normal, and two being wetter than normal. Delaware and Maryland each had their 11th driest March since recordkeeping began in 1895.

The U.S. Drought Monitor from March 7 showed 2 percent of the Northeast as abnormally dry. These areas included small parts southern Maryland, southern Pennsylvania, southern New Jersey, and New York's Long Island. By month's end, increasing precipitation deficits, below-normal streamflow, and declining soil moisture led to the introduction of moderate drought in southern/eastern Maryland and the introduction/expansion of abnormal dryness in Maryland, Delaware, southern New Jersey, and southeastern Pennsylvania. The U.S. Drought Monitor from March 28 showed 1 percent of the Northeast in moderate drought and 6 percent as abnormally dry.

A storm from March 3 to 4 brought localized heavy snowfall and gusty winds to the Northeast. The greatest storm snow totals of 12 to 18 inches were generally in higher elevations of eastern/northern New York and northern New England. Wind gusts reached 60 mph in multiple locations across the region, with a few higher gusts of up to 74 mph. A nor'easter dropped significant snowfall on parts of eastern/northern New York and New England from March 13 to 15. Multiple counties in these areas picked up at least 12 inches of snow, with the greatest storm snow totals reaching 36 inches in eastern New York and western Massachusetts and 42 inches in southern Vermont. The weight of the snow downed trees and power lines in parts of Massachusetts

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[70] NOAA National Centers for Environmental Information, Monthly National Climate Report for March 2023, published online April 2023, retrieved on October 18, 2023 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202303.

and New Hampshire, leaving some roads impassable. Between heavy snow and gusty winds, hundreds of thousands of customers in the Northeast lost power, with some outages lasting days. Whiteout conditions made travel difficult, resulting in hundreds of accidents. Some Northeast airports such as Logan International Airport in Boston, Massachusetts, and LaGuardia Airport in New York City had hundreds of delayed or cancelled flights. At Hancock International Airport in Syracuse, New York, a plane slid off a taxiway.