

# **Northeast Power Coordinating Council**

## **2021 Long Range Adequacy Overview**

**RCC  
Approved**

**November 30, 2021**

Conducted by the  
NPCC CP-8 Working Group



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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### NPCC CP-8 WORKING GROUP

Philip Fedora (Chair)	Northeast Power Coordinating Council, Inc.
Abdelhakim Sennoun Harêtha Alao	Hydro-Québec Distribution
Greg Drake	New York State Reliability Council
Prathamesh Kumthekar Ryan McSheffery	Énergie NB Power
Philip Moy Khatune Zannat	PSEG Long Island
Laura Popa Ben O'Rourke Swagata Sharma Sushil Silwal	New York Independent System Operator
Kamala Rangaswamy	Nova Scotia Power Inc.
Vithy Vithyananthan	Ontario Independent Electricity System Operator
Fei Zeng Manasa Kotha	ISO New England Inc.

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### Introduction

This study evaluated, on a consistent basis, the long-range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Regions' plans to meet their Loss of Load Expectation (LOLE) planning criteria <sup>1</sup> through a multi-area probabilistic assessment for the period from 2022 to 2026, based on the data reported within the *NERC 2021 Long-Term Reliability Assessment* <sup>2</sup> (LTRA).

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program <sup>3</sup> was selected by NPCC for this analysis. GE Energy Consulting was retained by the CP-8 Working Group to conduct the simulations. MARS version 4.4.1803 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's *NPCC Reliability Assessment for Summer 2021*, April 23, 2021, <sup>4</sup> was used as the starting point for this overview. CP-8 Working Group members reviewed the existing data and then revised it to reflect the conditions expected for the 2022-2026 period, consistent with the information reported for the *NERC 2021 Long-Term Reliability Assessment*.

This report is organized in the following manner: after a brief Introduction, general modeling assumptions are presented followed by a summary provided by each Area describing their specific modeling representation. The results and observations of this overview are then presented.

This overview's Objective and Scope of Work are shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

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<sup>1</sup> See: Directory No. 1- Section 5.2 <https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories>

<sup>2</sup> See: <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>

<sup>3</sup> See: [Product and Service Offerings](#) | GE Energy Consulting

<sup>4</sup> See: <https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2021/npcc-2021-summer-assessment.pdf> , Appendix VIII



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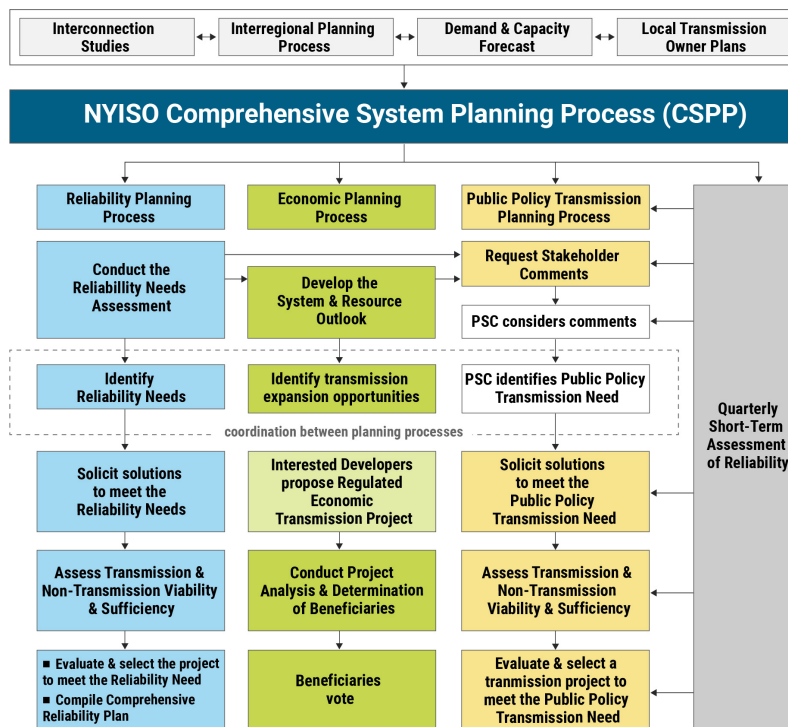
### Modeling Assumptions

The assumptions used in the NPCC Long Range Adequacy Overview are consistent with the data reported in *NERC 2021 Long-Term Reliability Assessment*.<sup>5</sup> and the following recently completed Area studies:

### Area Studies Summary

#### New York

The Comprehensive System Planning Process (CSPP) encompasses the New York Independent System Operator's (NYISO) transmission planning processes and is comprised of several components: 1) Local Transmission Planning Process (LTPP); 2) Reliability Planning Process (RPP) and the Short-Term Reliability Process (STRP); 3) Economic Planning Process (the former "CARIS"); and 4) Public Policy Transmission Planning Process (PPTPP). In concert with these four components, interregional planning is conducted with NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional planning and may consider Interregional Transmission Projects in its regional planning processes. The CSPP also provides for cost allocation and cost recovery in certain circumstances for regulated reliability, economic, and public policy transmission projects, as well as the coordination of interregional planning activities. The NYISO CSPP is illustrated in the figure below.



<sup>5</sup> See: <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>



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The RPP consist of two evaluations:

1. The Reliability Needs Assessment (RNA). The NYISO performs a biennial study in which it evaluates the resource and transmission adequacy and transmission system security of the New York Bulk Power Transmission Facilities (BPTF) over the RNA Study Period (now<sup>6</sup> years 4 through year 10). Through this evaluation, the NYISO identifies Reliability Needs on the Bulk Power Transmission Facilities (BPTFs) in accordance with the applicable Reliability Criteria, as promulgated by NERC, NPCC and NYSRC. This report is reviewed by NYISO stakeholders and approved by the NYISO's Board of Directors.
2. The Comprehensive Reliability Plan (CRP). After the RNA is complete, the NYISO requests the submission of market-based solutions to satisfy the Reliability Need. The NYISO also identifies a Responsible TO and requests that the TO submit a regulated backstop solution and that any interested entities submit alternative regulated solutions to address the identified Reliability Needs. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Reliability Needs and evaluates and selects the more efficient or cost-effective regulated transmission solution to the identified need, if necessary. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO triggers regulated solution(s) to satisfy the need. The New York ISO develops the CRP that sets forth its findings regarding the proposed solutions. The CRP is reviewed by the New York ISO stakeholders and approved by the New York ISO's Board of Directors.

Additionally, in 2019 the New York ISO proposed to stakeholders creating a Short-Term Reliability Process ("STRP") to evaluate and address reliability impacts resulting from both Generator deactivations and other drivers of Reliability Needs that are identified in a quarterly Short-Term Assessment of Reliability ("STAR") study. The New York ISO made a tariff filing at FERC to create the STRP in February 2020, requesting a May 1, 2020 effective date. The FERC accepted the NYISO filing on April 30, 2020, and the first quarterly STAR commenced on July 15, 2020. The New York ISO posted the first completed STAR report on October 13, 2020. The 2020 RNA also incorporated the effects of these tariff changes by assessing Reliability Needs in years 4-10 of the Study Period, while the STRP assesses five years from its start date, with a focus on addressing needs in years 1-3 of the Study Period.

### Summary of 2020 RNA and the 2021-2030 CRP

The *2020 Reliability Needs Assessment*<sup>7</sup> (RNA) assessed the resource adequacy and transmission security of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTFs) from year 2024 through 2030, the Study Period of this RNA.

Some of the key assumptions included:

- Load Forecast:
  - Provided in the 2020 Load & Capacity Data ("Gold Book"<sup>8</sup>)
- Transmission:

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<sup>6</sup> Effective May 1, 2020, the scope of the RNA is limited to years 4-10 of the planning horizon while the NYISO Short-Term Reliability Process addresses years 1-3 and also assesses years 4-5. The STRP addresses needs in years 4-5 only if they cannot be addressed by the RPP.

<sup>7</sup> 2020 RNA November Report: <https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf>

<sup>8</sup> <https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/>



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- Provided in the 2020 Gold Book which includes:
  - Western New York Public Policy
  - AC Transmission Public Policy
- Generation Additions:
  - Applied the RNA inclusion rules which resulted in including:
    - 646 MW of wind generation
    - 23 MW of solar generation
  - Approximately 1,800 MW of BTM solar added by 2025
- Generation Removed:
  - The last coal-fired generations units at Somerset and Cayuga were deactivated in the cases.
  - The Indian Point 2 and Indian Point 3 nuclear units are deactivated in May 2020 and May 2021 respectively.
  - The New York State Department of Environmental Conservation’s “Peaker Rule.”<sup>9</sup> will result in approximately 1,500 MW of combustion turbine peaker capability located mainly in the New York City, Hudson Valley and Long Island to become unavailable phasing in from 2023 to 2025.

The 2020 RNA identified violations or potential violations of reliability criteria (“Reliability Needs”) in the base case throughout the entire study period (2024-2030) due to dynamic instability, transmission overloads, and resource deficiencies. The key conclusions are:

- The 2020 RNA has identified resource adequacy LOLE violations starting 2027 and increasing through 2030; while 2026 is at the 0.1 days/year criterion.
- The 2020 RNA also identified transmission security violations of reliability criteria in the base case throughout the entire RNA study period (2024-2030) due to dynamic instability and transmission overloads.

The issues identified were primarily driven by a combination of forecasted peak demand and the assumed unavailability of certain generation in New York City affected by the New York State Department of Environmental Conservation’s “Peaker Rule.” After the RNA was published and before pursuing a solicitation for solutions, the NYISO considered subsequent updates to system plans. These updates included a reduced demand forecast to account for economic and societal effects from the COVID-19 pandemic, and new local transmission plans and operating procedures by Con Edison for the New York City service territory. With these updates, there are no remaining violations of reliability design criteria.

In addition to the base case set of assumptions and findings, the RNA provides an assessment of risks to the bulk electric grid under certain scenarios to inform stakeholders and policymakers of potential alternate outcomes. Scenarios are variations on key base case assumptions such as higher load forecast, capacity removal, or deviations from assumed system plans. If they occurred, the events analyzed in the scenarios could change the timing, location, or degree of reliability issues identified in the base case. Each of these variations of the base case indicates potential increased risks of reliability criteria violations in the future.

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<sup>9</sup> The “Peaker Rule” is the commonly-used name for a New York State Department of Environmental Conservation (“DEC”) regulation that limits nitrogen oxides (NOx) emissions from simple-cycle combustion turbines during periods of peak load. Units that were impacted by this rule needed to file compliance plans by March 2, 2020. Based on those compliance plans a subset of those generators would be unavailable during summer peak periods phasing in from 2023 to 2025.



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The scenarios include higher peak load than forecasted, additional generator retirements, a “status quo” case in which major transmission and generation plans fail to come to fruition, and examination of a system powered by 70% renewable energy by 2030 (“70x30 scenario”), the latter based on the 2019 Economic Planning Process (formerly CARIS) 70x30 assumptions and outputs. The 70x30 Scenario is based on the New York State Climate Leadership and Community Protection Act (CLCPA), which mandates that New York consumers be served by 70% renewable energy by 2030 (70x30). The CLCPA includes specific technology-based targets for distributed solar (6,000 MW by 2025), energy storage (3,000 MW by 2030), and offshore wind (9,000 MW by 2035), and ultimately establishes that the electric sector will be emissions free by 2040.

Additional studies led by the NYISO, such as the Climate Change<sup>10</sup> and Grid in Transition<sup>11</sup>, provide further insights into the future grid under various renewable penetration assumptions. The NYISO’s Power Trends report<sup>12</sup> is the NYISO’s annual flagship publication on New York’s electric system.

### The 2021-2030 Comprehensive Reliability Plan (CRP)

The 2021-2030 Comprehensive Reliability Plan (CRP) is the second part of the 2020-2021 Reliability Planning Process following the 2020 RNA, and it concludes that the New York State Bulk Power Transmission Facilities as planned will meet all currently applicable reliability criteria from 2021 through 2030 for forecasted system demand in normal weather. While the NYISO finds that there are no remaining long-term actionable reliability needs to be addressed in this cycle of the Reliability Planning Process, the margin to maintain reliability over the next ten years will narrow or could be eliminated based upon changes in forecasted system conditions. Risk factors such as delayed implementation of projects in this plan, additional generator deactivations, unplanned outages, and extreme weather could potentially lead to deficiencies in reliable electric service in the coming years. The CRP also includes additional analysis of the reliability challenges to meeting the 70 x 30 requirement and to achieving an emissions-free electric system by 2040.

The 2021-2030 CRP targets December 2021 for action by the NYISO’s Board of Directors.

### **Summary of the STARS**

The first STAR performed was the 2020 Q3 STAR<sup>13</sup>, which assessed the resource adequacy and transmission security of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTF) from year 2021 through 2025, with a focus on years 2021 – 2023. The key assumptions were the same as those in the 2020 RNA.

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<sup>10</sup> NYISO’s Climate Change Reports: <https://www.nyiso.com/library>

<sup>11</sup> NYISO’s Grid in Transition Report: <https://www.nyiso.com/documents/20142/2224547/Grid-in-Transition-Executive-Summary.pdf>

<sup>12</sup> NYISO’s 2021 Power Trends: <https://www.nyiso.com/documents/20142/2223020/2021-Power-Trends-Report.pdf>

<sup>13</sup> 2020 Q3 STAR Report: <https://www.nyiso.com/documents/20142/16004172/2020-Q3-STAR-Report-vFinal.pdf>



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The 2020 Q3 STAR identified violations or potential violations of reliability criteria (“Reliability Needs”) in the base case starting in 2023. The key conclusions were:

- The Q3 2020 STAR identified that the planned system through 2025 is within the resource adequacy criterion of 0.1 days/year loss of load expectation (LOLE).
- The 2020 Q3 STAR identified dynamic instability starting in 2023 and continuing through 2025. The issues include low transient voltage response, loss of generator synchronism, and undamped voltage oscillations. The assessment also identified transmission overloads beginning in year 2025. The short-term needs observed in 2023 are Near-Term Reliability Needs and solutions will be addressed in accordance with the NYISO Short-Term Reliability Process.
- The needs observed in years 2024 and 2025 were identical to those identified in the 2020 Reliability Needs Assessment (“RNA”), and therefore were addressed in the long-term Reliability Planning Process.

Market based and backstop solutions were solicited and received. In consideration of all proposed solutions, only the Con Edison proposal was deemed viable and sufficient to meet the Near-Term Reliability Needs from the 2020 Q3 STAR. Con Edison proposed to revise the operational status of certain series reactors as listed in the 2020 Q3 STAR report. The planned series reactor status changes would be made for the summer period and would become effective starting in summer 2023. Therefore, the NYISO selected the Con Edison regulated transmission solution.

Subsequent quarterly STARs were performed and, to date, have identified no additional Reliability Needs. The 2021 Q4 STAR is in progress at the time of writing this section, targeting January 13, 2022 for completion. The NYISO’s STAR reports are posted here: <https://www.nyiso.com/short-term-reliability-process>

### New England

The New England assumptions used in this overview are consistent with the data reported in the *NERC 2021 Long-Term Reliability Assessment*,<sup>14</sup> the *2021-2030 Forecast Report of Capacity, Energy, Loads and Transmission* (2021 CELT)<sup>15</sup> data and the *NPCC 2020 New England Comprehensive Review of Resource Adequacy*.<sup>16</sup>

ISO-New England (ISO-NE) develops an independent demand forecast for its Balancing Authority (BA) Area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecasts are considered coincident. This peak demand forecast is the gross peak demand forecast, which is then decreased to a net peak demand forecast by subtracting the impacts resulting from conservation/energy efficiency (EE) measures and behind-the-meter photovoltaics (BTM PV). ISO-NE is a summer-peaking, electrical bulk

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<sup>14</sup> See: <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>

<sup>15</sup> See: <https://www.iso-ne.com/system-planning/system-plans-studies/celt/>

<sup>16</sup> See: <https://www.npcc.org/content/docs/public/library/resource-adequacy/2020/2020-12-01-new-england-comprehensive-review.pdf>



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power system (BPS). ISO-NE's 50/50 reference demand forecast is based on the reference economic forecast, which reflects the economic conditions that are expected to occur within New England.

Over the assessment period 2022 through 2026, the 50/50 New England net summer peak demand (gross peak demand minus behind-the-meter photovoltaic (BTM PV) resources) is expected to increase from 27,645 MW for the summer of 2022 to 28,181 MW by the summer of 2026. The 536 MW increase in net peak demand represents a 1.94% growth during the 5-year period.

The annual New England net energy for load<sup>17</sup> is expected to increase from 123,847 GWh in 2022 to 126,557 GWh by 2026. The 2,710 GWh increase in net energy for load represents 2.19% in energy growth during the same 5-year study period.

Annually, ISO-NE forecasts the load reduction impact of BTM PV resources, and the reductions to peak demand and energy due to passive DR programs that are comprised mostly of EE. EE resources are projected to grow from 2,856 MW in 2022 to 3,703 MW by 2026. This represents an 847 MW (29.7%) increase during the 5-year study period. Meanwhile, total demand resource programs are expected to decrease by 194 MW over the study period, from 4,085 MW in 2022 to 3,891 MW by 2026, which reflects a 4.75% reduction.

In 2020, ISO-NE included its first electrification forecast within its load forecast. The new electrification forecast reflects the added electricity demand associated with heat pumps (within the residential and commercial space heating sector) and electric vehicles (EVs) (within the transportation sector). Heat pumps are not projected to add demand to the New England summer peak loads since they are primarily designed for winter operation. ISO-NE's future EV summer demand is forecast to be 25 MW on peak with 146 GWh of energy in 2022, and 202 MW on peak and 1,219 GWh of energy in 2026.

On June 1, 2018, ISO-New England integrated price-responsive DR into the energy and reserve markets. In 2021, approximately 587 MW of DR participates in these markets and is dispatchable (i.e., treated similar to generators). Regional DR will increase to 678 MW by 2024 and this value is assumed constant/available thru the remainder of the assessment period.

Resource additions from November 2021 through May 2023 consist mainly of solar and wind resources with approximately 70 MW of hydro resource uprates. Total Tier 1 nameplate capacity additions by mid-2023 amount to approximately 522 MW.

New England currently (summer 2021) has 182 MW (1,486 MW nameplate) of wind generation and 836 MW (2,645 MW nameplate) of BTM PV. As of April 26, 2021, approximately 19,700 MW (nameplate) of wind generation projects have requested generation interconnection studies. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of

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<sup>17</sup> New England annual net energy for load accounted for load reduction from BTM PV and energy efficiency.



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diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of the summer peaks to later in the day.

Generating capacity that has been added since 2020 consists primarily of 495 MW nameplate of solar capacity. Existing certain capacity for 2021 is 29,860 MW. Approximately 160 MW of Tier 1 solar and 15 MW of wind capacity is projected to be added by 2022. Tier 2 capacity additions scheduled for 2022 include 257 MW of solar generation. In 2023, scheduled Tier 2 capacity additions total 2,193 MW of wind and solar generation, 779 MW of battery storage projects, and 207 MW of natural-gas-fired generation.

Resource retirements are expected to total approximately 2,553 MW by mid-2024. Known retirements include:

Projected Retirement Date	Station Name	Summer Capacity (MW)
June 2022	Mystic 7 and Jet	522
June 2023	South Meadow 11 - 14	146
June 2024	Mystic 8 & 9	1,413
		Total = 2,081 (MW)

New England is interconnected with the three Balancing Areas (Bas) of Quebec, the Maritimes, and New York. ISO-NE takes into account the transmission transfer capability between these BAs to assure that their limits are accounted for in regional resource adequacy assessments. ISO-NE's Forward Capacity Market (FCM) methodology limits the purchase of import capacity based on these interconnection transfer limits. ISO-NEs capacity net imports are assumed to range from 1,059 MW to 1,487 MW during the 2022 to 2024 period and decrease to 0 MW starting in 2025.

The region has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While a number of major projects are nearing completion, four significant projects remain under construction. The table below highlights these transmission projects.<sup>18</sup>

<sup>18</sup> As taken from ISO-NE's Final RSP Project List – Planning Advisory Committee (PAC) Presentation, dated October 20, 2021. Located on the ISO-NE web site at: [https://www.iso-ne.com/static-assets/documents/2021/10/final\\_project\\_list\\_presentation\\_oct\\_2021.pdf](https://www.iso-ne.com/static-assets/documents/2021/10/final_project_list_presentation_oct_2021.pdf)



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	PPA	TCA	Construction
Southeast MA/RI Reliability (SEMA/RI)	Approved 5/17, 4/18	TCA Submitted	Project completion 2017-2025
Greater Boston – North, South, Central and Western Suburbs	Approved 4/15, 5/15, 6/16	TCA Submitted	Project completion 2013-2023
Eastern CT 2029	Approved 6/21	Not Submitted	Project completion 2021-2026
Boston Area Optimized Solution (BAOS)	Approved 5/21	TCA Submitted	Project completion 2023

### Ontario

The Ontario assumptions used in this study are consistent with the data reported in the *NERC 2021 Long-Term Reliability Assessment*.<sup>19</sup>

Over the 2022 to 2026 forecast period, Ontario peak demand is expected to increase by about 1.05% annually. The peak demands are shaped by two competing factors: those that increase the demand for electricity and those that act to reduce the requirement for grid supplied electricity. The increased demand for electricity is being driven by population growth, economic expansion and increased penetration of electric devices. Offsetting the growth are reductions from conservation energy efficiency and codes and standards (C&S) savings, electricity price responsiveness, and increased output by embedded generation.<sup>20</sup>

Recent policy changes have led to lower committed energy efficiency savings and when combined with the lower growth rates of renewable embedded generation, lessening much of the downward pressure on forecast peak demands going forward. Increased adoption of electric vehicles and trends to decarbonize should provide long term growth to Ontario's electricity sector.

Contracted wind resources amounting to 160 MW are expected to be added to the grid. Substantial resource turnover is anticipated in the coming years, driven by nuclear retirements, nuclear refurbishments and by the expiry of contracted resources.

Nuclear refurbishments at Bruce and Darlington generating stations are expected to reduce the generation capacity availability in the coming years. During the refurbishment period, one to four units are expected to be on outage at any given time, including peak seasons. Once they return to service, they will continue to help meet Ontario's adequacy requirements in the mid/longer term. The operator of Pickering NGS

<sup>19</sup> See: <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>

<sup>20</sup> *Contracted Embedded Generation* (or *Embedded Generation* for short) refers to generators that supply electricity to local distribution systems and have power purchase agreements (contracts) with the IESO. They do not participate in the IESO-administered market, but rather reduce demand on the transmission grid. Since these generators have contracts with the IESO, the IESO can track their existing and future capacities.



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has received approval for extending the operation of two units to the fall of 2024, from 2022, and the remaining four units to the end of 2025, from the end of 2024.

In December 2020, the IESO held its first capacity auction securing 992 MW of capacity from resources including generation, imports, storage, and DR. The target capacities for the December 2021 capacity auction will be 1,000 MW for the summer 2022 obligation period, and 500 MW for the winter 2022/2023 obligation period as announced in the IESO's 2021 [Annual Acquisition Report \(AAR\)](#).

The IESO performs resource assessments and identifies resource shortfalls in its Annual Planning Outlook (APO) over a 20-year horizon. The AAR translates planning and operational information, such as the forecasts outlined in the APO and bulk and regional plans, into a series of procurement and market activities designed to meet the needs identified.

These activities include the evolution and expansion of the capacity auction, and a series of competitive procurements to secure resources to meet resource adequacy over all horizons. The IESO will initiate an RFP for up to 750 MW in late 2021 with a three-year commitment period beginning in 2026, to address adequacy needs. The IESO intends to launch an RFP for at least 1,000 MW in fall 2022 for a commitment period of at least seven years.

As part of the Amended and Restated Capacity Sharing Agreement between Ontario and Quebec, signed in November 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As a result of the previous agreement, Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. The IESO and NYISO facilitates trading of capacity from Ontario to New York. To ensure reliability in Ontario is maintained, only capacity that is determined by the IESO to be above Ontario's required reserve margin levels, over summer or winter season, are exported.

The East-West Tie Expansion project consists of a new 230 kV transmission line roughly paralleling the existing East-West Tie Line between Wawa and Thunder Bay. The new line will increase the electricity transfer capability into Northwest Ontario and will improve the flexibility and efficiency of the Northwest electricity system. As part of this project, upgrades are being planned for the Lakehead, Marathon and Wawa transformer stations to accommodate the new line. The planned in-service date of the project is Q1 2022.

### Québec

The Québec Area assumptions used in this study are consistent with the data reported in the [\*NERC 2021 Long-Term Reliability Assessment\*](#).<sup>21</sup>

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<sup>21</sup> See: <https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>



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Demand 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. EE and conservation programs are integrated in the demand forecasts.

The Québec Area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,500 MW on winter 2021-2022 peak demand. The area is also expanding its existing interruptible load program for commercial buildings which will grow from 325 MW in 2021-2022 to 470 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 28 MW for winter 2021-2022 to 621 MW for winter 2028-2029. The enhancement of interruptible program for large industrial customers will have an additional potential capacity that varies from 310 MW in 2023-2024 winter period to 480 MW at the end of the study period.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 88 MW for winter 2021-2022, increasing to 330 MW for winter 2031-2032. Moreover, 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-Quebec's request. Their contribution as a resource is expected to be around 178 MW for winter 2021-2022 and around 230 MW at the end of the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction.

The Romaine-4 unit (245 MW) is expected to be fully operational by the end of 2022. The refurbishment of the Rapide-Blanc generating station is expected to start this year and the next return to service is expected to be in 2022. The integration of small hydro unit accounts for 41 MW new capacity during the assessment period. For other renewable resources, 48 MW (17 MW on-peak value) is expected to be in service by the end of 2021. Additionally, 19 MW of new biomass is expected to be in service by the end of 2022.

A new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord region and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction phase and planned to be in service in 2022.

### **Maritimes Area**

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick (NB), Nova Scotia, Prince Edward Island (PEI), and Northern Maine. NB Power is the Reliability Coordinator for the Maritimes Area with its system operator functions performed by its Transmission and System Operator division under a regulator approved Standards of Conduct.

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. The peak Area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of New Brunswick and Nova Scotia which are historically highly coincidental (typically between 97% and 99%). Demand for the Maritimes Area is determined to be the non-coincident sum of the peak



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loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LRAO assessment period. The Maritimes Area peak loads are expected to increase by 4.7% during summer and by 1.3% during winter seasons over the 5-year assessment period. This translates to compound average growth rates of 0.9% in summer and 0.2% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 1.7% during the 5-year assessment period for an average growth of 0.4% per year.

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 5-year LRAO assessment period in the Maritimes Area, annual amounts for summer peak demand reductions associated with Energy Efficiency and Conservation programs rise from 43 MW to 106 MW while the annual amounts for winter peak demand reductions rise from 133 MW to 321 MW.

The DER installed capacity in Nova Scotia is approximately 200 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar. Based on an LOLE analysis, the existing wind resources are assumed to have an effective load carrying capability (ELCC) of 19% and BTM solar is assumed to have an ELCC of 0%. Nova Scotia has shown embedded BTM solar PV projections of 19 MW in 2021 rising to 175 MW by 2031. These projects include distributed small-scale solar (mainly rooftop) that fall under Nova Scotia Power's net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of Nova Scotia Power's system peak (winter evenings). Prince Edward Island has shown an increase of embedded BTM solar PV projections of 7 MW in 2021 rising to 18 MW by 2031; with higher interest due to new provincial subsidies. The planned DER capacity in New Brunswick is 2.8 MW starting 2021-22. New Brunswick has no future projections to report but does anticipate that DER could increase rapidly over the next ten years and potentially impact operation of the distribution system in particular. Since the amounts of DER resources that will be allowed to operate on the system is unknown at this time, New Brunswick Power does not forecast specific DER amounts and all such resources are included as "Energy Efficiency and Conservation" for LRAO purposes.

New Brunswick Power's 2020 Integrated Resource Plan assumes extending 28 MW diesel fired generator and 290 MW of natural gas fueled resource starting 2025 and 2026 respectively. In New Brunswick, there is a reduction of 20 MW of community-based wind project, totaling the community owned wind projects to 58 MW name plate capacity by 2022-23. In New Brunswick, unconfirmed retirements include a hydro facility of 4 MW at the end of its service life pending regulatory approval and a 98 MW Power Purchase Agreement contract.



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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In Nova Scotia, Tier 1 resources include tidal projects with a total installed capacity of 32 MW expected to be phased in over the 5-year study period. Nova Scotia Power completed an Integrated Resource Plan (IRP) in 2020 and developed an IRP Reference Plan. However, the specific type, quantity and timing of future resource additions and retirements in the Reference Plan remain uncertain. As a result, the changes in the Reference Plan have been included as Tier 3 resources in the assessment. These Tier 3 resources include natural gas additions of approximately 10 MW in 2023, and 150 MW in 2026, mainly combustion turbines and a small reciprocating engine. Additional Tier 3 resources include a 10 MW battery in 2023. As per the IRP Reference Plan, these resource additions along with potential firm capacity imports could facilitate the retirement of approximately 320 MW coal-fired generation and 170 MW of gas-fired generation within the assessment period. However, these imports and retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 2) of up to 31 MW are expected to be installed in Prince Edward Island in 2022-23 timeframe. Prince Edward Island also plans to add new 50 MW of thermal capacity (Tier 3) during the year 2026. NMISA projects new solar additions (Tier 1-3) of approximately 117 MW name plate during this LRAO study period. New Brunswick de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. Nova Scotia and Prince Edward Island de-rate wind capacity to 19% and 15% respectively of nameplate based on year-round calculated equivalent load carrying capacities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Nova Scotia Power includes a relatively small 10MW battery added as a Tier 3 resource in 2023. Pilot projects and internal studies are underway to further understand the economics, application and performance of battery storage resources. Ongoing internal analyses are conducted by New Brunswick Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks. These analyses are in a very preliminary stage. The value of energy storage options is expected to increase as the technology improves and as New Brunswick's smart grid network develops. These studies would be evaluated further as the economics around these options become viable. Construction of a 475 MW +/-200 kV high voltage direct current (HVDC) undersea cable link (Maritime Link) between Newfoundland and Labrador and Nova Scotia was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in Nova Scotia in late 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern NB area.



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### Load Representation

The loads for each area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies.

#### Load Shape

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the winter 2013 – 2014 load shape is now used for the winter assessments. The selection of these load shapes was based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008 and 2013 through 2020:

- ✓ a 2002 load shape representative of a summer weather pattern with a typical expectation of hot days; and,
- ✓ a 2013/14 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

Review of the results for both load shape assumptions indicated only slight differences in the results. The Working Group agreed that the weather patterns associated with the 2013/14 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments. Upon review of subsequent winter weather experience, the Working Group agreed to replace the 2003/04 load shape with the 2013/14 load shape assumption for this analysis.

For a study such as this that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2002, 2013, and 2014. January through March of the composite shape was based on the data for January through March of 2014. The months of April through September were based on those months for 2002, and October through December was based on the 2013 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2013 and 2014 were adjusted by the ratios of their annual energy to the annual energy for 2002. This adjustment removed the load growth that had occurred from 2002, from the 2013 and 2014 loads, so as to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match each Area's monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

#### Load Forecast Uncertainty

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

model in the GE MARS program. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, Table 1(a) shows the values assumed for January 2022, corresponding to the assumed occurrence of the NPCC winter peak load (assuming the composite load shape) and Table 1(b) shows the values assumed for August 2022, corresponding to the NPCC summer peak load. Table 1 also shows the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, the reliability indices were calculated for the expected load conditions, derived from computing the reliability at each of the seven load levels modeled, and computing a weighted-average expected value based on the specified probabilities of occurrence.

**Table 1(a)**  
**Per Unit Variation in Load Assumed (Month of January 2022)**

Area	Per-Unit Variation in Load						
HQ	1.086	1.086	1.043	1.000	0.952	0.902	0.902
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.082	1.032	0.983	0.970	0.940	0.865	0.800
NY	1.110	1.069	1.033	1.000	0.970	0.943	0.918
ON	1.058	1.041	1.021	1.000	0.975	0.948	0.919
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

**Table 1(b)**  
**Per Unit Variation in Load Assumed (Month of August 2022)**

Area	Per-Unit Variation in Load						
HQ	1.077	1.077	1.038	1.000	0.969	0.944	0.923
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.229	1.104	1.003	0.919	0.900	0.856	0.851
NY	1.133	1.089	1.041	0.990	0.934	0.874	0.815
ON	1.145	1.101	1.051	1.000	0.947	0.894	0.849
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

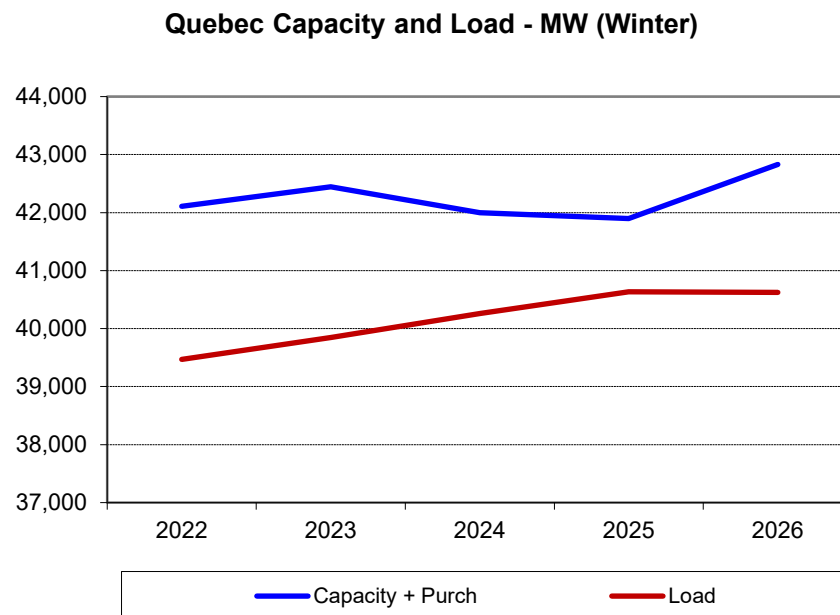
### Generation

#### Generator Unit Availability

Details regarding the NPCC area's assumptions for generator unit availability are described in the latest NPCC Seasonal Multi-Area Probabilistic Assessment.<sup>22</sup>

#### Capacity and Load Summary

Figures 1 through 6 summarize area capacity and load assumed in this Overview at the time of area peak for the period 2022 to 2026. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance. More details can be found in Appendix B.



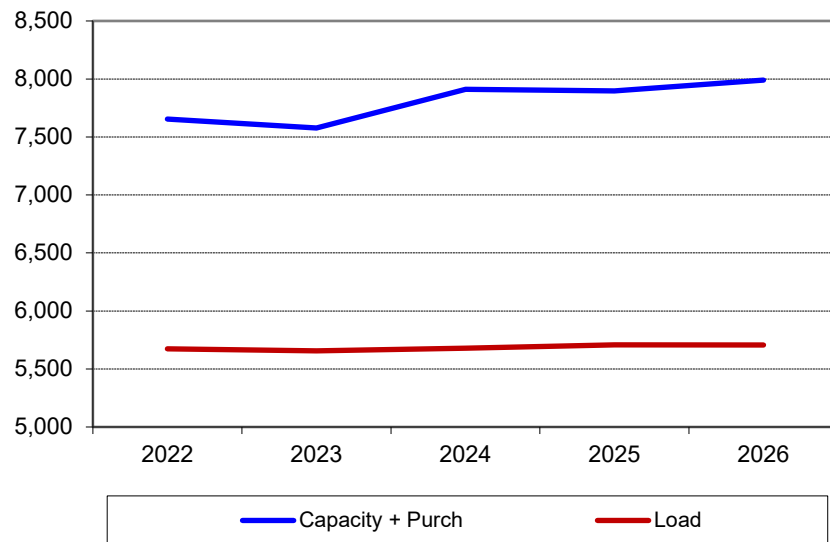
**Figure 1 – Quebec Winter Capacity and Load**

<sup>22</sup> See: <https://www.npcc.org/library/reports/seasonal-assessment>



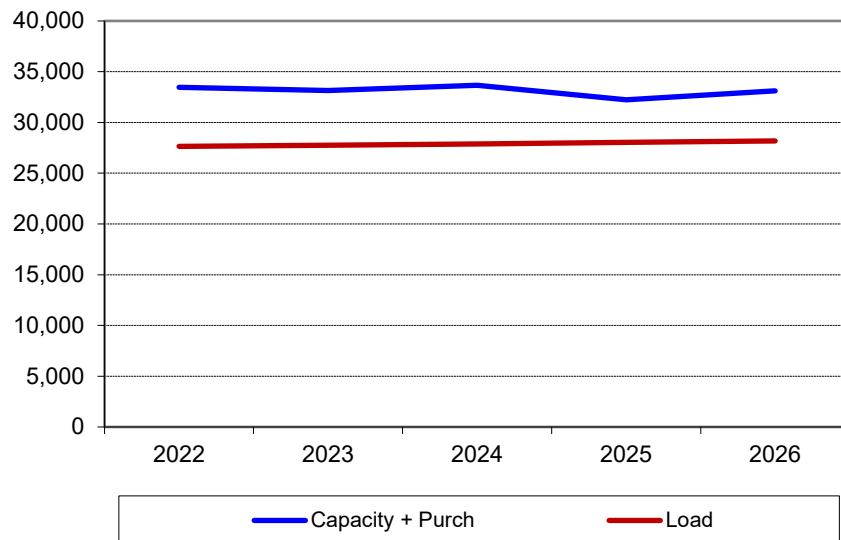
## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

**Maritimes Capacity and Load - MW (Winter)**



**Figure 2 – Maritimes Winter Capacity and Load**

**New England Capacity and Load - MW (Summer)**

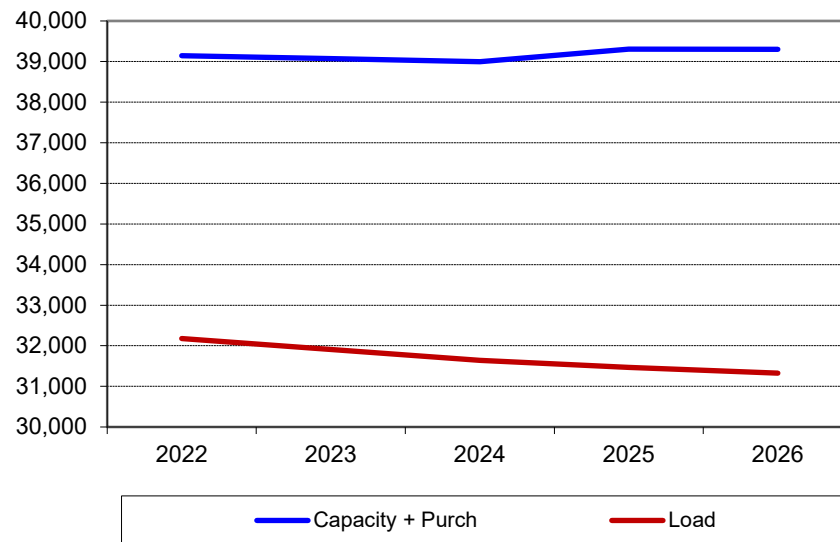


**Figure 3 – New England Summer Capacity and Load**



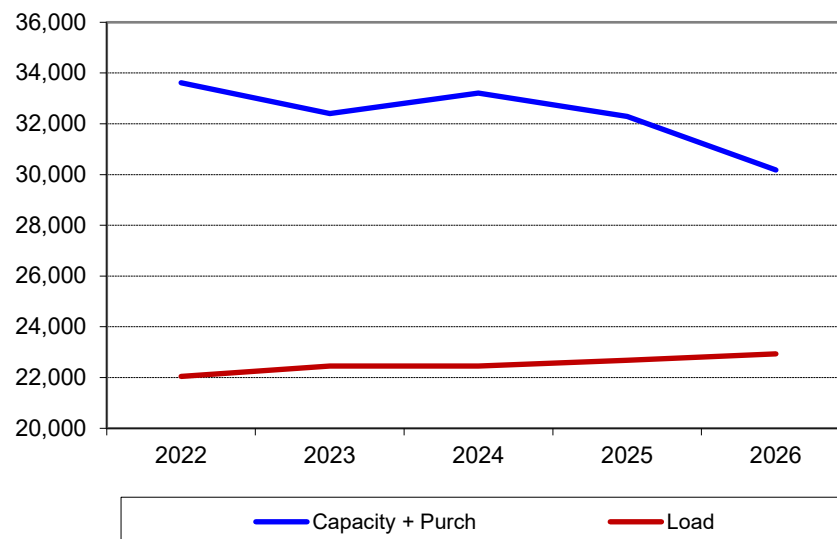
## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

**New York Capacity and Load - MW (Summer)**



**Figure 4 – New York Summer Capacity and Load**

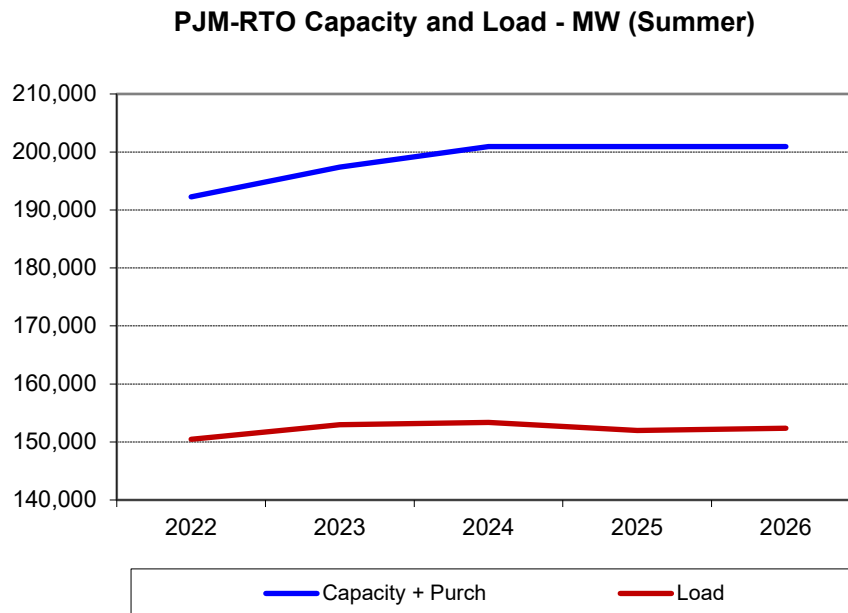
**Ontario Capacity and Load - MW (Summer)**



**Figure 5 – Ontario Summer Capacity and Load**



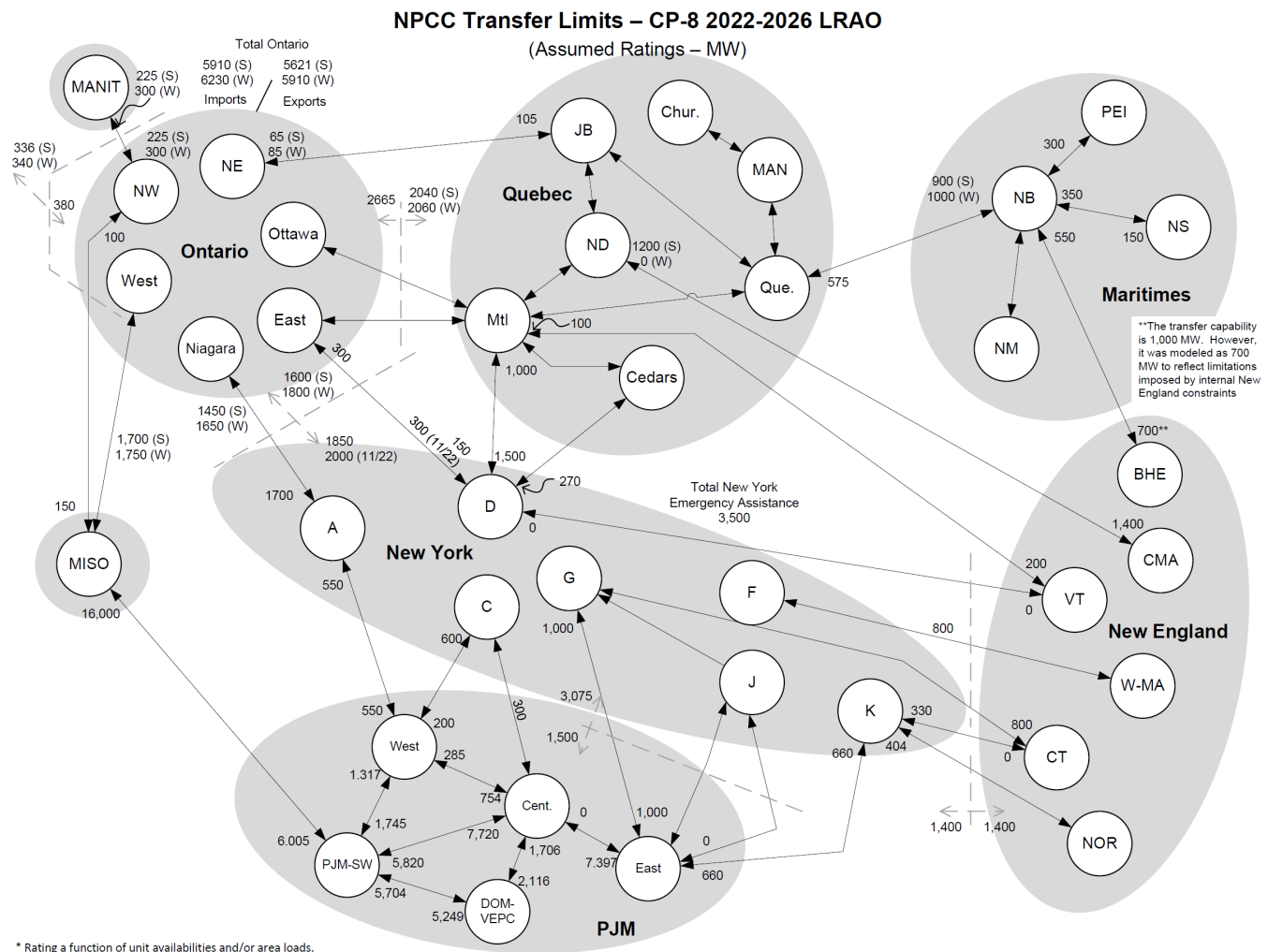
## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW



**Figure 6 – PJM-RTO Summer Capacity and Load**

## Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2022 to 2026.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York. <sup>23</sup>

**Figure 7 - Assumed Transfer Limits**

<sup>23</sup> See: [http://www.oasis.oati.com/HQT/HQTdocs/2014-04\\_DEN\\_et\\_CORN-version\\_finale\\_en.pdf](http://www.oasis.oati.com/HQT/HQTdocs/2014-04_DEN_et_CORN-version_finale_en.pdf)



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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Transfer limits between and within some areas are indicated in Figure 7 with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 7 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
W MA	- Western MA	NS	- Nova Scotia	Dom-VEPC	- Dominion Virginia Power
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	MT	- Maritimes Area
MISO	- Mid-Continent Independent System Operator	Que	- Québec Centre		



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Operating Procedures to Mitigate Resource Shortages

Each area takes predefined steps as their reserve levels approach critical levels. These steps consist of load control and generation supplements that can be implemented by System Operators before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under abnormal or emergency conditions, and/or reducing operating reserves. Table 2 summarizes the load relief assumptions modeled for each NPCC area.

**Table 2**  
**NPCC Operating Procedures to Mitigate Resource Shortages**  
**Peak Month 2022 Load Relief Assumptions - MW**

<b>Actions</b>	<b>HQ (Jan)</b>	<b>MT (Jan)</b>	<b>NE (Aug)</b>	<b>NY (Aug)</b>	<b>ON (Jun)</b>
1. Curtail Load	1,532	-	-	-	-
Appeals	-	-	-	-	1% of load
RT-DR/SCR/EDRP	-	-	-	873 <sup>24</sup>	-
SCR Load /Man. Volt. Red.	-	-	-	0.21% of load	-
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction	250	-	260	1.0% of load	1.3% of load
Interruptible Loads	-	277	-	207	390
4. No 10-min Reserves	750	505	-	-	945
General Public Appeals	-	-	-	80	-
5. 5% Voltage Reduction	-	-	-	-	0.64% of load
No 10-min Reserves	-	-	980	1,310	-

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

<sup>24</sup> Derated value shown accounts for assumed availability.



## **NPCC 2021 LONG RANGE ADEQUACY OVERVIEW**

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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 2 was a reasonable approximation for this analysis.

### **Assistance Priority**

All Areas may receive assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Modeling of Neighboring Regions

The modeling of the PJM-RTO is shown in Figure 7. The PJM-RTO was divided into five distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, PJM West, and PJM South. This represents a slight departure from modeling practices prior to 2014 in which PJM West and PJM South were modeled as one region (PJM Rest). This modeling change was justified on grounds that the PJM South area (Dominion Virginia Power) is a member of SERC while practically all the PJM West area is a member of RFC. Furthermore, PJM West and PJM South are now two separate areas in the PJM Capacity Market framework (PJM's Reliability Pricing Model).

A detailed representation of the neighboring region of MISO (Midcontinent Independent System Operator) was also assumed. The demand and capacity assumptions for PJM and the MISO for 2022 are summarized in Table 3 and Figure 8.

**Table 3**  
**PJM and MISO 2022 Assumptions** <sup>25</sup>

	<b>PJM</b>	<b>MISO</b>
<b>Peak Load (MW)</b>	150,463	91,860
<b>Peak Month</b>	July	August
<b>Assumed Capacity (MW)</b>	193,198	107,008
<b>Purchase/Sale (MW)</b>	-939	-173
<b>Reserve (%)</b>	33.6	21.0
<b>Operating Reserves (MW)</b>	3,400	3,906
<b>Curtaillable Load (MW)</b>	8,824	4,350
<b>No 30-min Reserves (MW)</b>	2,765	2,670
<b>Voltage Reduction (MW)</b>	2,201	2,200
<b>No 10-min Reserves (MW)</b>	635	1,236
<b>Appeals (MW)</b>	400	400
<b>Load Forecast Uncertainty</b>	+/- 13.9%, 9.3%, 4.6%	+/- 11.1%, 7.4%, 4.6%

<sup>25</sup> Load and capacity assumptions for RFC-Other and MRO-US based on NERC's Electricity, Supply and Demand Database (ES&D) available at: <http://www.nerc.com/~esd/>



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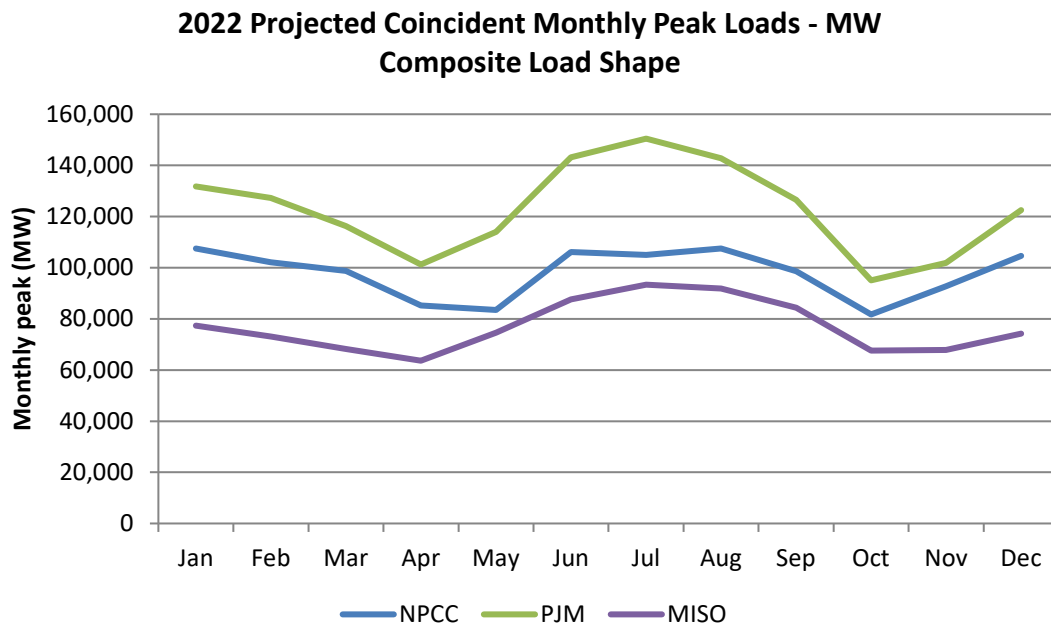


Figure 8 – 2022 Projected Monthly Expected Peak Loads for NPCC, PJM and MISO

### MISO

The Mid-Continent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets in all or parts of 15 states in the US. Beginning with the 2015 NPCC Long Range Adequacy Overview, (LRAO) the MISO region (minus the recently integrated Entergy region) was included in this analysis replacing the RFC-OTH and MRO-US regions. In previous versions of the LRAO, RFC-OTH and MRO-US were included to represent specific areas of MISO, however due to difficulties in gathering load and capacity data for these two regions (since most of the reporting is done at the MISO level), it was decided to start including the entirety of the northern MISO region within the model.

The 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. The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, dated January 2021. Load Forecast Uncertainty was modeled consistent with recent PJM planning models considering seven load levels, each with an associated



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years that the model is based on, sampling size, and how many years in the future for which the load forecast is being derived.

### **Expected Resources**

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Load Management (LM) is modeled as an Emergency Operating Procedure. The total available MW as LM is per results from the PJM's capacity market.

### **Expected Transmission Projects**

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



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Results

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2022-2026 period for the 50/50 expected load level.<sup>26</sup>

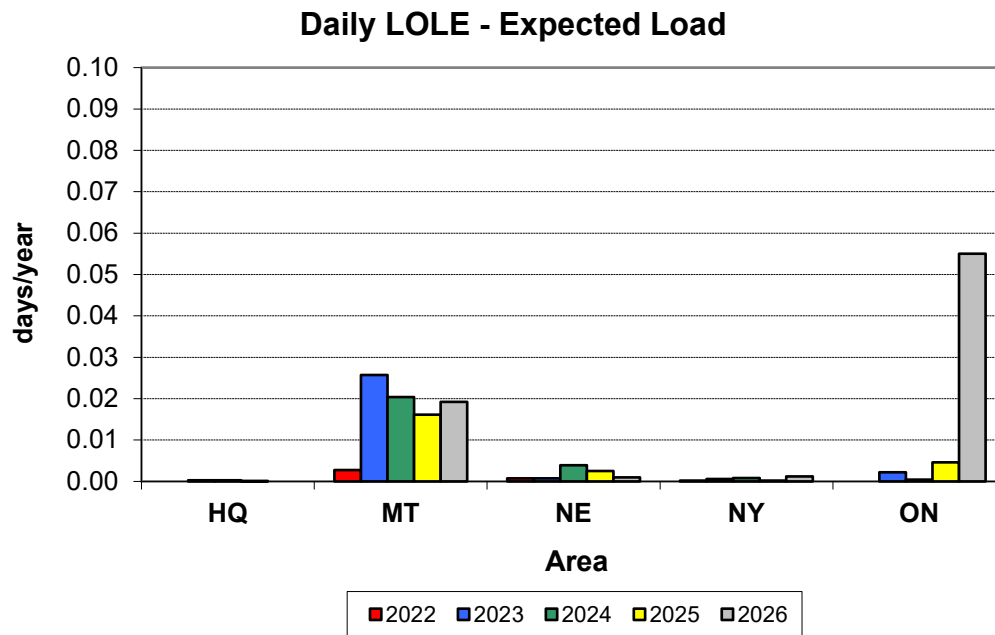


Figure 9(a) - Estimated Annual NPCC Area LOLE (2022 – 2026)

<sup>26</sup> The 50/50 expected load level results were based on the probability-weighted average of all seven load levels simulated



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

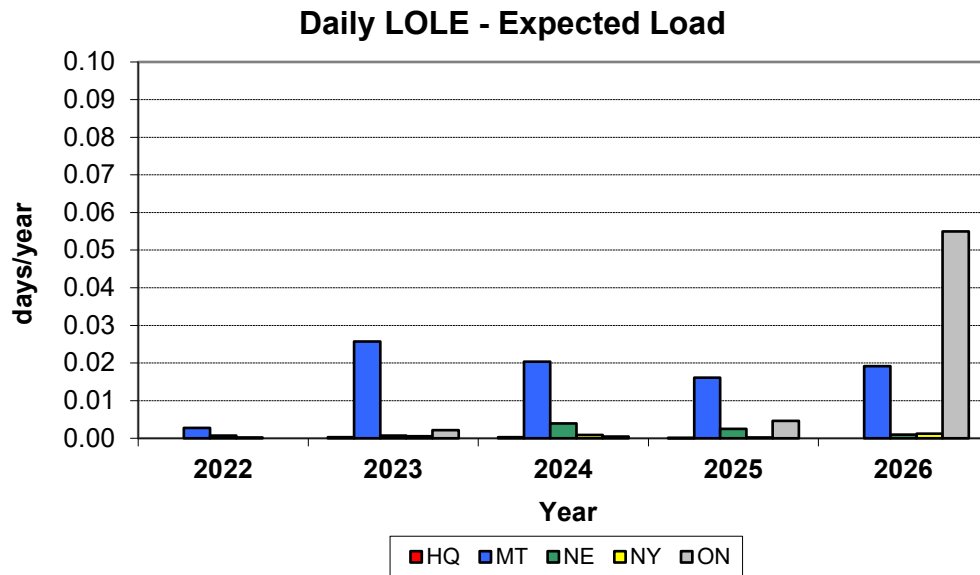


Figure 9(b) - Estimated Annual NPCC Area LOLE (2022– 2026)

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region’s Loss of Load Expectation (LOLE) for the 2022-2026 period for the 50/50 expected load level.

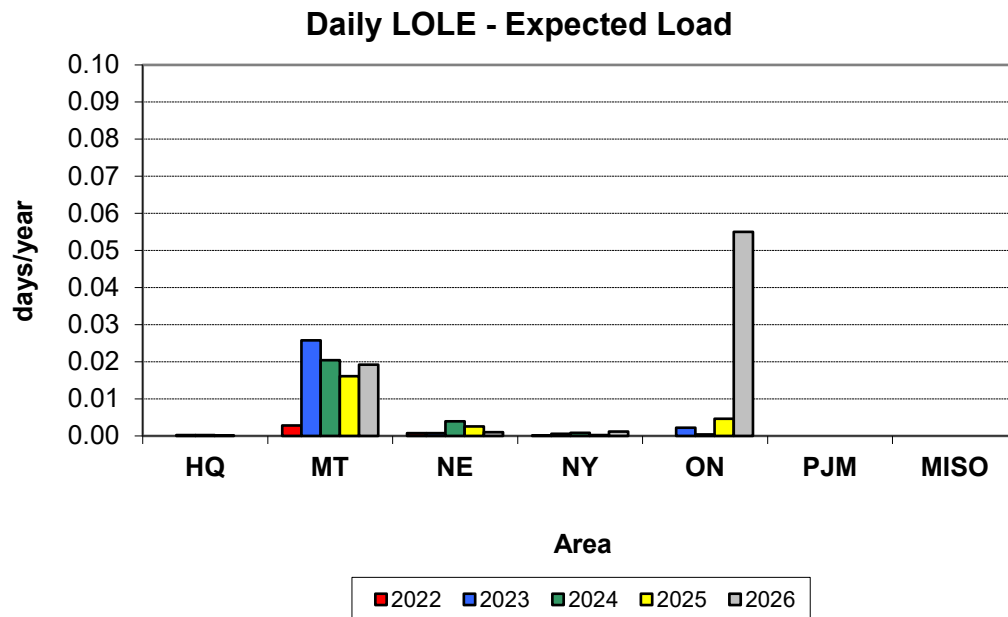
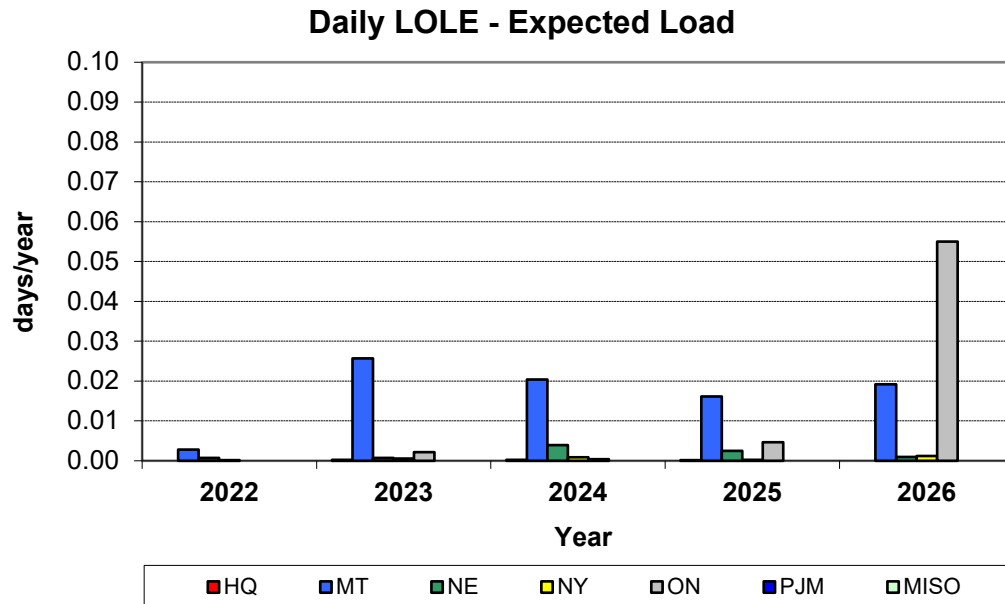


Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2022 – 2026)

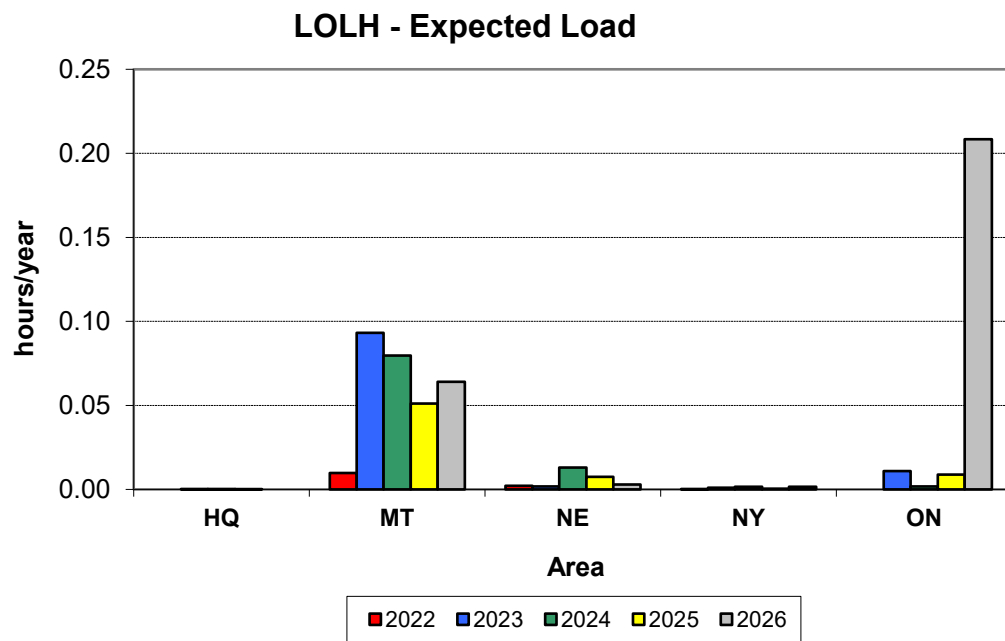


## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW



**Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region’s LOLE (2022 – 2026)**

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2022-2026 period for the 50/50 expected load level.



**Figure 10(a) - Estimated Annual NPCC Area LOLH (2022 – 2026)**



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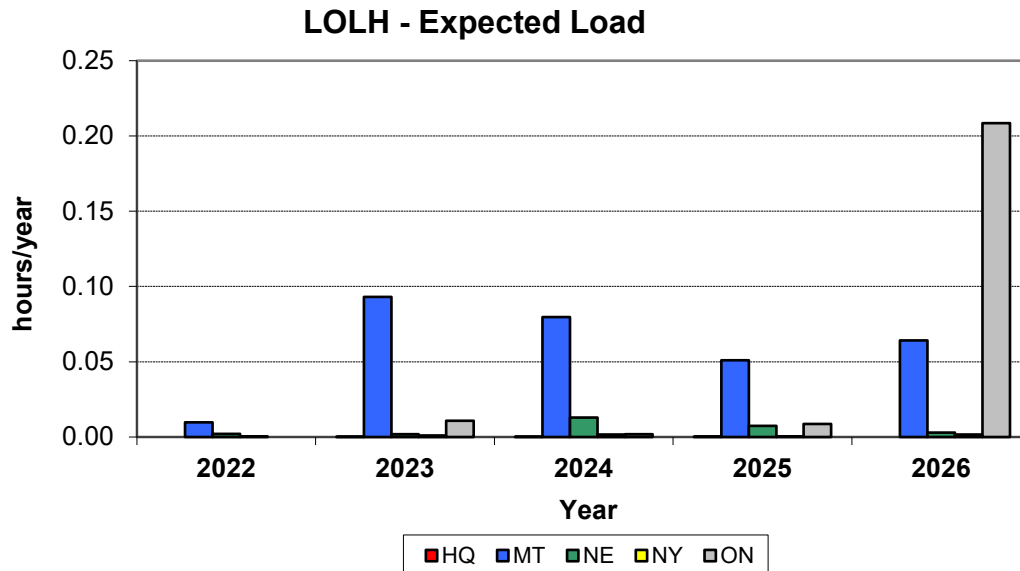


Figure 10(b) - Estimated Annual NPCC Area LOLH (2022 – 2026)

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLE) for NPCC Areas and neighboring Regions for the 2022-2026 period for the 50/50 expected load level.

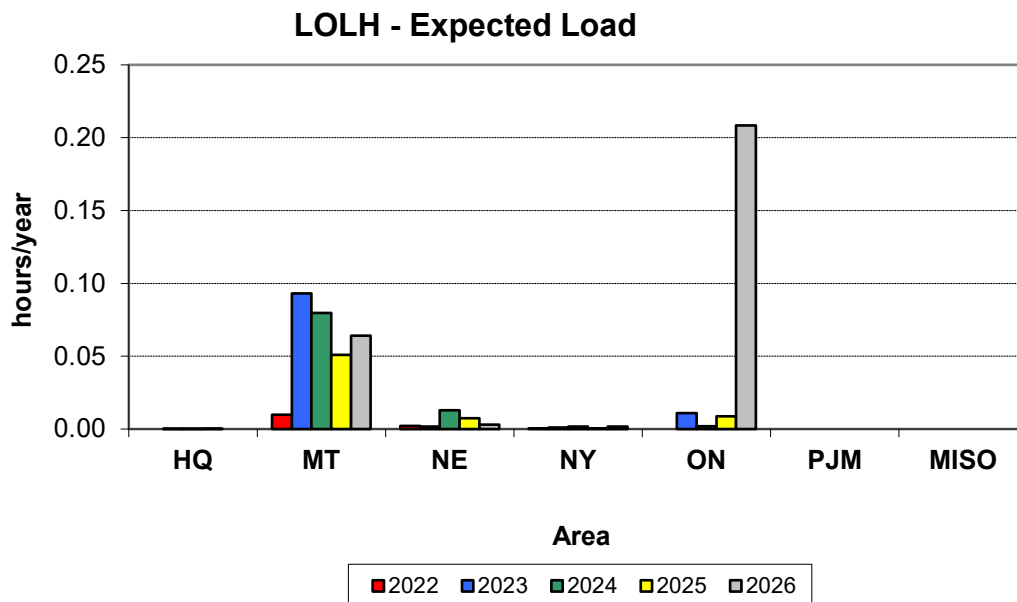
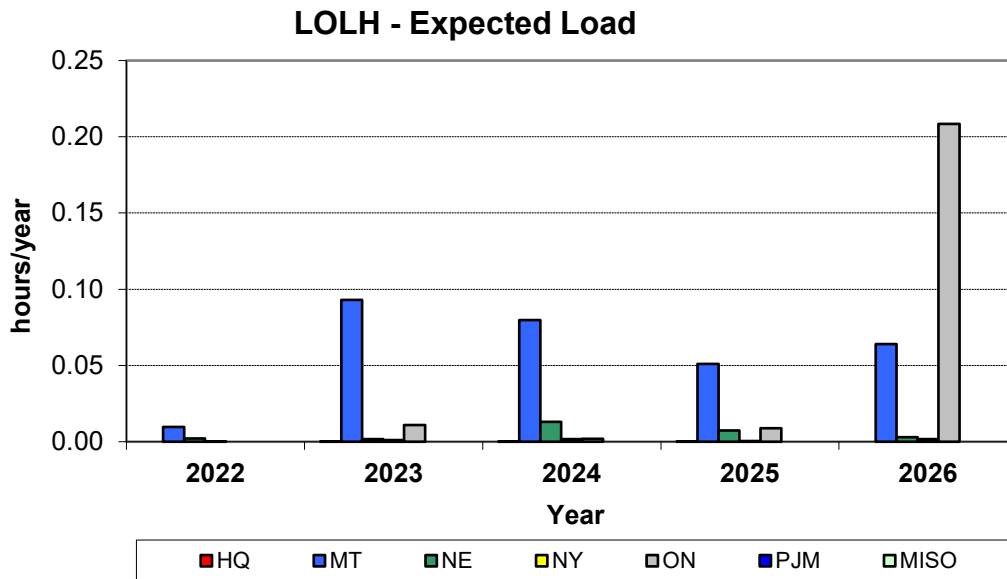


Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2022 – 2026)

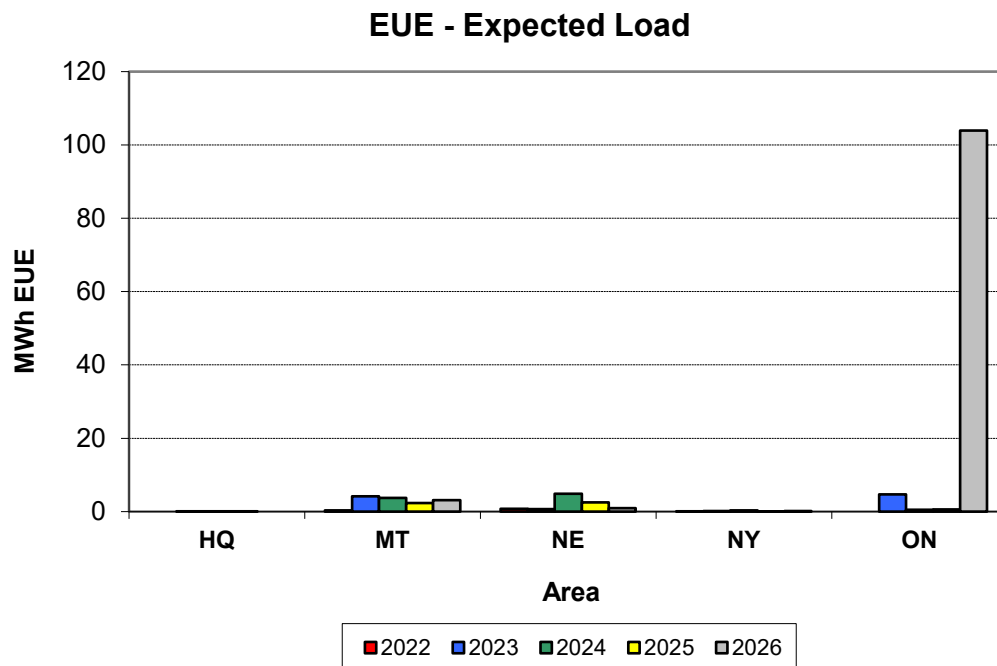


## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW



**Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2022 – 2026)**

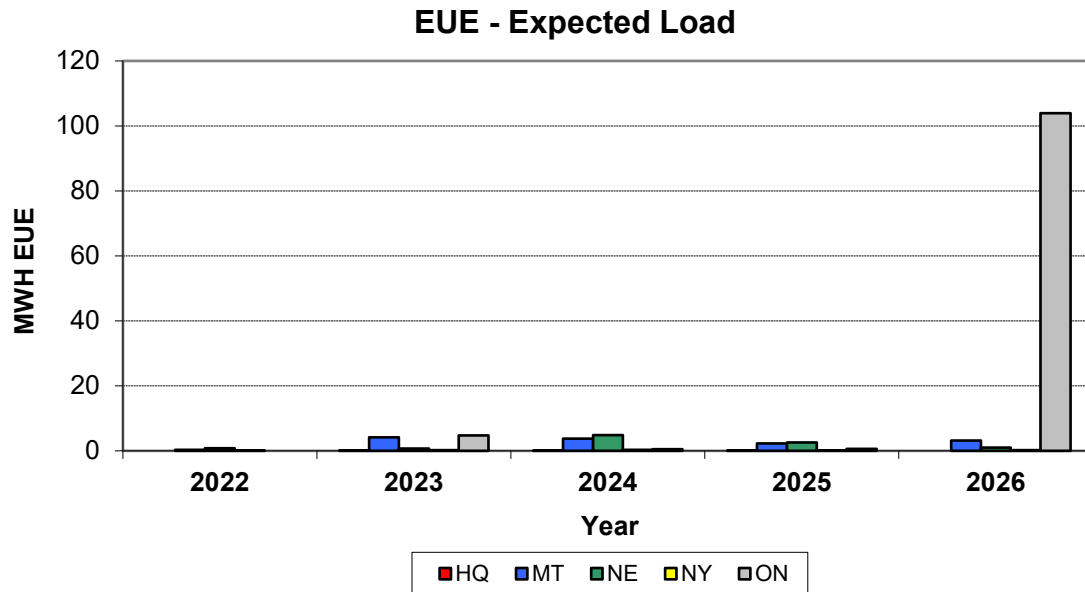
Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2022-2026 period for the 50/50 expected load level.



**Figure 11(a) - Estimated Annual NPCC Area EUE (2022 – 2026)**

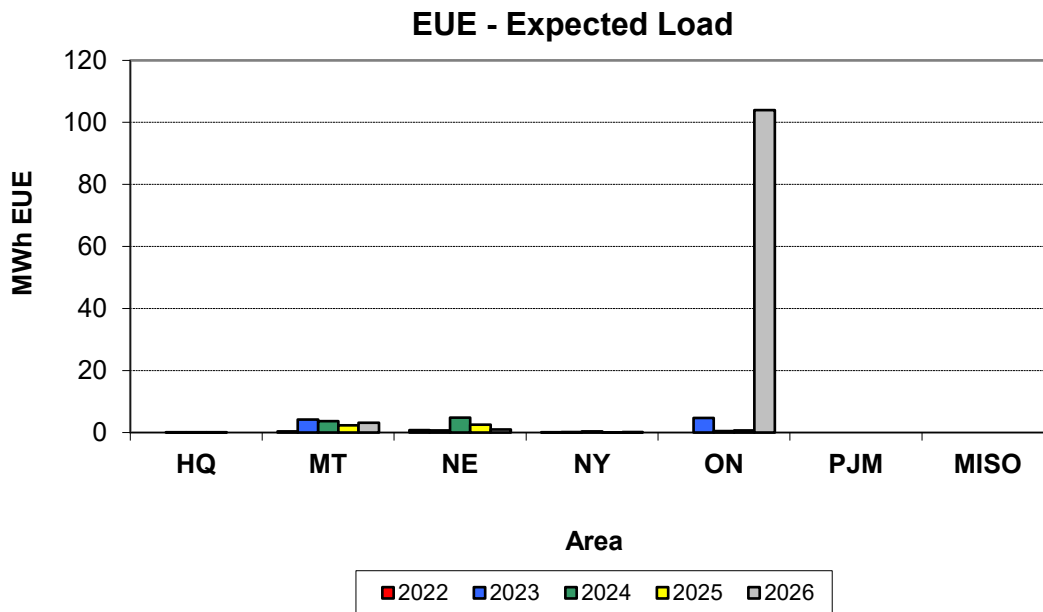


## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW



**Figure 11(b) – Estimated Annual NPCC Area LOLH (2022 – 2026)**

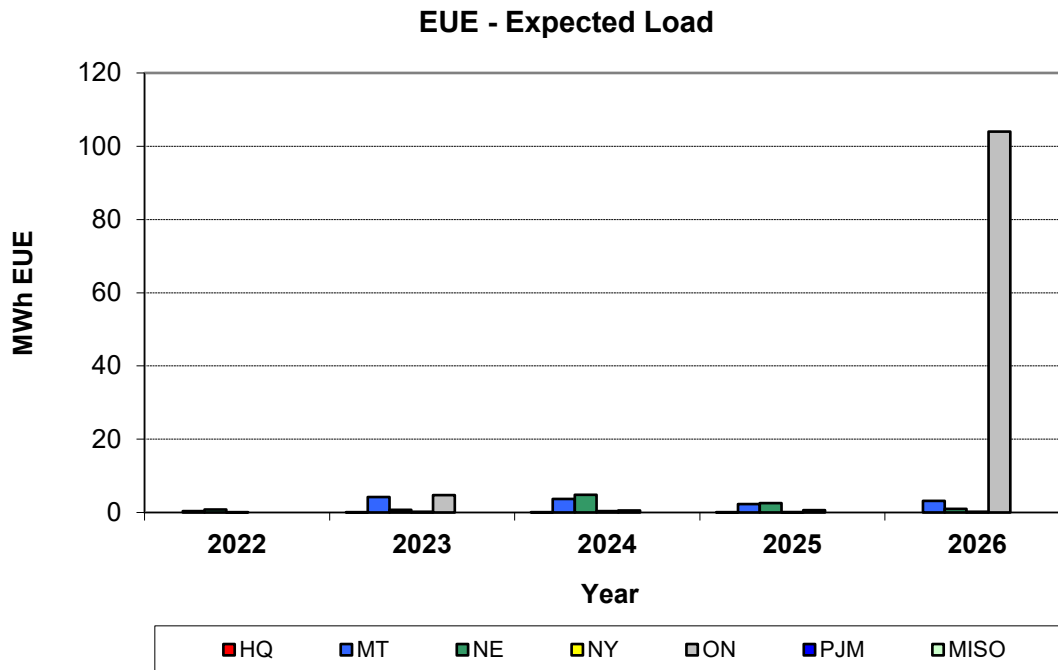
Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2022-2026 period for the 50/50 expected load level.



**Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2023 – 2026)**



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**Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2022 – 2026)**

Table 4 (below) shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount reported in the *NERC 2021 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS program calculation for the total estimated NPCC annual energy is within approximately 2% of the corresponding sum of the NPCC Areas annual energy forecasts.

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Table 4 –Comparison of Energies Modeled (Annual GWh)

Year	2022	2023	2024	2025	2026
<b>Québec</b>					
MARS	194,773	197,141	198,243	199,494	199,881
2021 LTRA	191,544	194,963	197,662	198,794	200,662
MARS - LTRA	3,229	2,179	581	700	-781
%(MARS-LTRA)/LTRA	1.69%	1.12%	0.29%	0.35%	-0.39%
<b>Maritimes</b>					
MARS	28,486	28,661	28,629	28,634	28,740
2021 LTRA	27,666	27,755	28,110	28,121	28,147
MARS - LTRA	819	906	519	513	593
%(MARS-LTRA)/LTRA	2.96%	3.27%	1.85%	1.82%	2.11%
<b>New England</b>					
MARS	133,886	134,675	135,860	136,563	138,005
2021 LTRA	123,847	124,567	125,393	125,747	126,557
MARS - LTRA	10,039	10,108	10,467	10,816	11,448
%(MARS-LTRA)/LTRA	8.11%	8.11%	8.35%	8.60%	9.05%
<b>New York</b>					
MARS	149,553	148,065	146,587	145,375	144,507
2021 LTRA	150,480	148,900	147,320	146,170	145,330
MARS - LTRA	-927	-835	-733	-795	-823
%(MARS-LTRA)/LTRA	-0.62%	-0.56%	-0.50%	-0.54%	-0.57%
<b>Ontario</b>					
MARS	135,147	137,929	140,710	142,123	143,950
2021 LTRA	135,055	137,834	140,613	142,026	143,853
MARS - LTRA	92	95	97	97	97
%(MARS-LTRA)/LTRA	0.07%	0.07%	0.07%	0.07%	0.07%



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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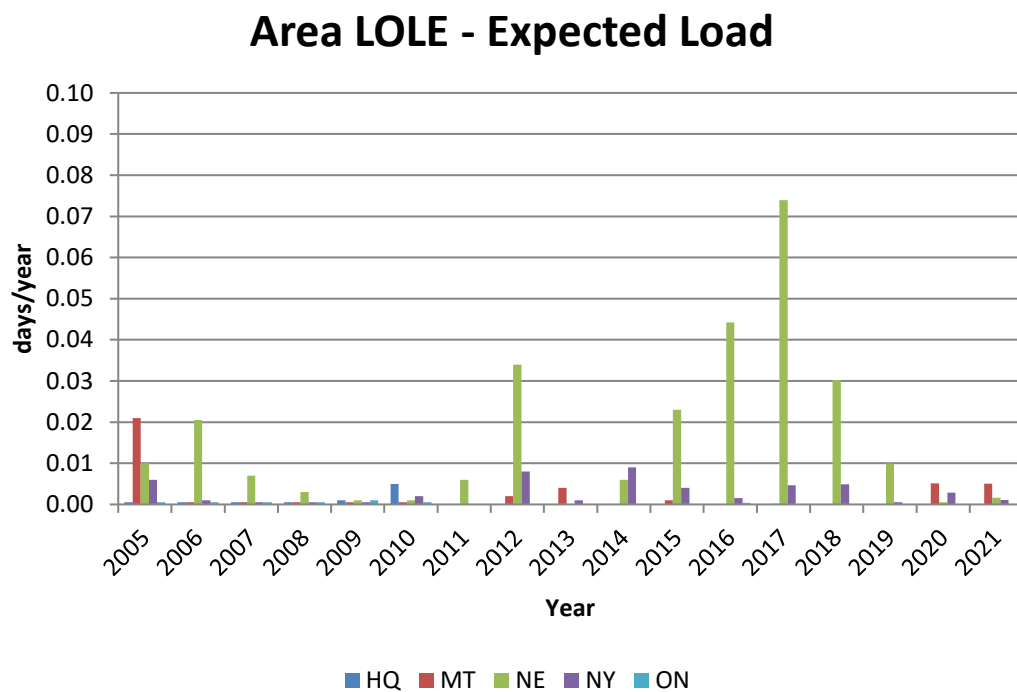
Year	2022	2023	2024	2025	2026
NPCC					
MARS	641,845	646,471	650,028	652,189	655,083
2021 LTRA	628,592	634,019	639,098	640,858	644,549
MARS - LTRA	13,252	12,453	10,931	11,332	10,534
%(MARS-LTRA)/LTRA	2.11%	1.96%	1.71%	1.77%	1.63%



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Observations

Figures 12(a) and 12(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the 50/50 expected load level.

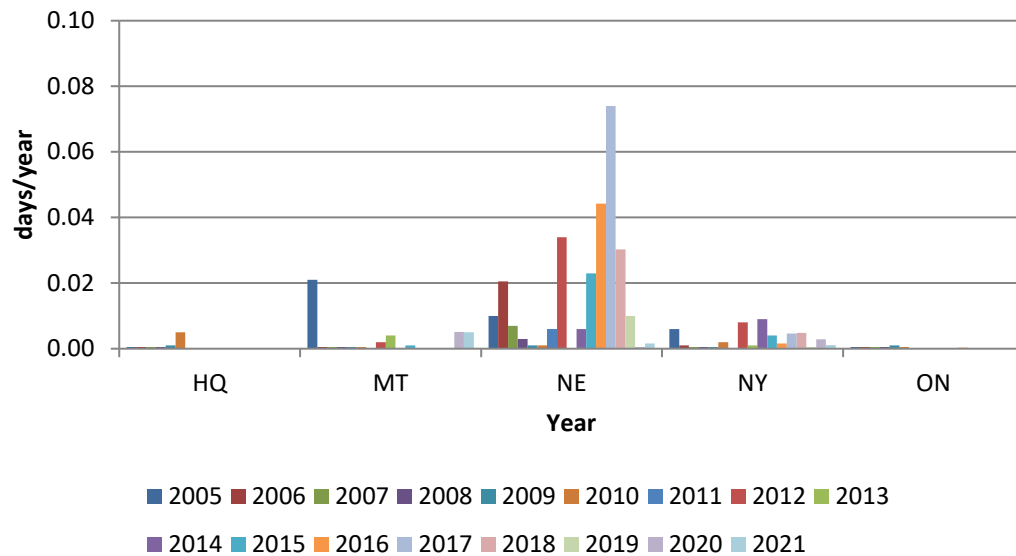


**Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)**



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Area LOLE - Expected Load



**Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)**

This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 13(a) and 13(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2022 – 2026 for the 50/50 expected load level.



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Area LOLE - Expected Load

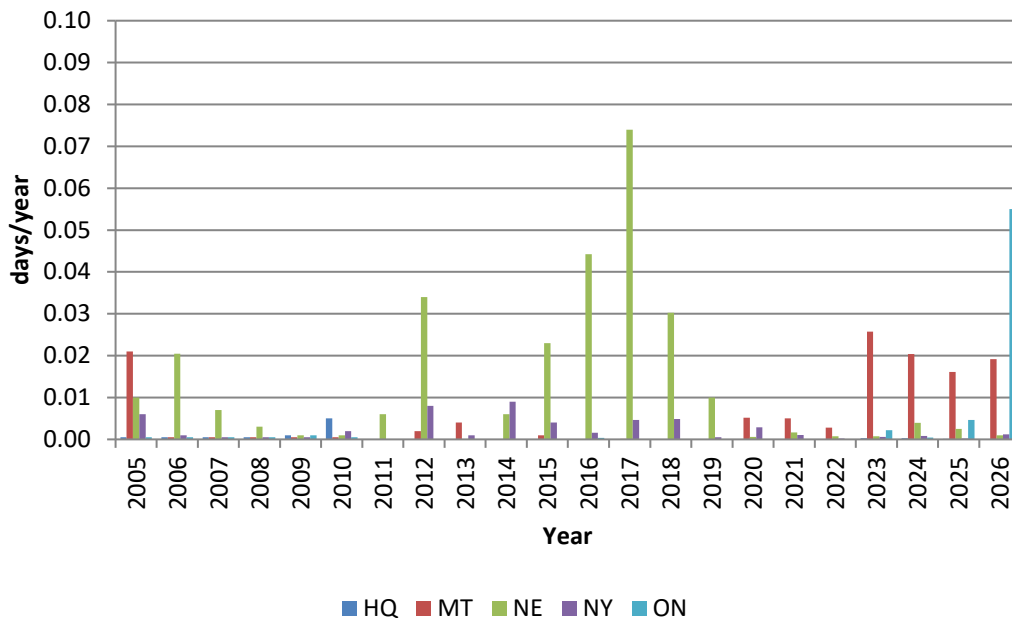


Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

### Area LOLE - Expected Load

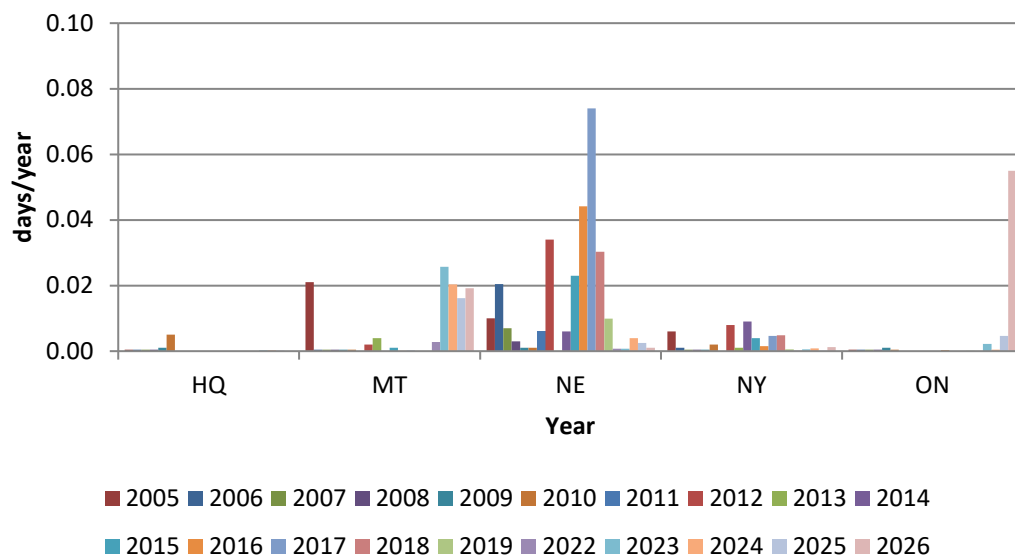


Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

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### Appendix A: **Objective and Scope of Work**

#### **2021 NPCC GE MARS Multi-Area Probabilistic Planning Database**

##### **1. Objective**

Using input from each Area, NPCC and its consultant will develop a planning 5-year ahead (2022 – 2026 assessment period) General Electric (GE) Multi-Area Reliability Simulation (MARS) Database, in order to facilitate NPCC Area Resource Adequacy studies and related NERC Reliability Assessment Subcommittee probabilistic analysis. To the extent possible, a detailed reliability representation for Regions bordering NPCC for the assessment period will be modeled.

The resultant GE MARS model will reflect NPCC Area and neighboring regional proposed plans and applicable demand forecast.

##### **2. Scope**

The CP-8 Working Group's GE MARS database will be used to develop a planning model suitable for the years 2022 – 2026, consistent with the NPCC Area and neighboring Regional data reported in the 2021 NERC Long-Term Reliability Assessment, recognizing:

- ✓ uncertainty in forecasted demand,
- ✓ scheduled outages of transmission,
- ✓ forced and scheduled outages of generation facilities, including fuel supply disruptions,
- ✓ the impacts of Sub-Area transmission constraints,
- ✓ the impacts of proposed load response programs; and,
- ✓ as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

#### **2021 NPCC Long Range Adequacy Overview**

##### **1. Objective**

Utilize the GE MARS program with the 2021 NPCC MARS Planning Database to estimate the annual Loss of Load Hours and Expected Unserved Energy for the NPCC Areas, consistent with related NERC *2021 NERC Long-Term Reliability Assessment* probabilistic analysis requirements.

##### **2. Scope**

Review the NPCC 2020 ProbA Base Case results and assess the validity of the NPCC 2020 ProbA results (with assumptions) *for the 2021 NERC Long-Term Reliability Assessment*. All NERC Assessment Areas are required to consider their sensitivity case results and/or insights in their off-year NERC Prob A and may choose to conduct another probabilistic study of their choice, or analytical approach.



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

### Appendix B: Modeled Capacity and Load

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
<b>2022</b>	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
<b>Capacity (MW) *</b>	41,894	7,721	32,180	37,248	33,617	193,198	107,008
<b>Purchase/Sale (MW)</b>	213	-66	1,292	1,892	0	-939	-173
<b>Load (MW)</b>	39,469	5,674	27,644	32,178	22,045	150,463	91,860
<b>Nameplate Demand Response (MW)</b>	1,982	277	2,856	873	390	8,824	4,350
<b>Active Demand Response (MW)</b>	0	0	682	0	0	0	0
<b>Reserves (%)</b>	11.7	39.8	31.4	24.4	54.3	33.6	21.0
<b>Maintenance - Peak Week (MW)</b>	**	0	0	6	20	0	0
<b>Wind Output at time of Area Peak (MW) ***</b>	1,375	438	182	489	1,657	1,960	2,341
<b>Wind Nameplate Capacity (MW)</b>	3,820	1,208	1,331	2,052	4,943	1,960	2,341

\* Wind capacity included at nameplate rating; demand response not included in capacity

\*\* Capacity for Quebec reflects scheduled maintenance and restrictions

\*\*\* This value reflects the expected value during peak, although the modeling varies across areas: Quebec, New England, PJM and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles; <sup>27</sup> Ontario utilizes random draws using a probability density function during the Monte Carlo simulation.

<sup>27</sup> The values shown represent the average wind generation in the top ten load hours, and does not represent the effective load carrying capability of the wind units or the firm capacity value.



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
<b>2023</b>	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
<b>Capacity (MW) *</b>	42,112	7,726	32,079	37,093	32,402	198,350	108,286
<b>Purchase/Sale (MW)</b>	330	-149	1,059	1,981	0	-939	-173
<b>Load (MW)</b>	39,846	5,656	27,746	31,910	22,454	152,967	92,914
<b>Nameplate Demand Response (MW)</b>	1,783	277	3,035	873	390	8,861	4,320
<b>Active Demand Response (MW)</b>	0	0	584	0	0	0	0
<b>Reserves (%)</b>	11.0	38.9	30.4	25.2	46.0	34.8	21.0
<b>Maintenance - Peak Week (MW)</b>	**	0	0	6	68	0	0
<b>Wind Output at time of Area Peak (MW) ***</b>	1,375	453	184	600	1,669	2,006	2,485
<b>Wind Nameplate Capacity (MW)</b>	3,820	1,358	1,351	2,603	4,943	2,006	2,485



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
<b>2024</b>	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
<b>Capacity (MW) *</b>	42,140	7,984	32,177	37,193	33,208	201,871	108,577
<b>Purchase/Sale (MW)</b>	-141	-72	1,486	1,804	0	-939	-173
<b>Load (MW)</b>	40,261	5,680	27,885	31,641	22,458	153,371	93,154
<b>Nameplate Demand Response (MW)</b>	1,987	277	3,213	873	390	8,888	4,294
<b>Active Demand Response (MW)</b>	0	0	678	0	0	0	0
<b>Reserves (%)</b>	9.3	44.2	32.2	26.0	49.6	36.8	21.0
<b>Maintenance - Peak Week (MW)</b>	**	0	0	6	146	0	0
<b>Wind Output at time of Area Peak (MW) ***</b>	1,375	435	340	279	1,768	2,018	2,551
<b>Wind Nameplate Capacity (MW)</b>	3,820	1,608	2,151	2,603	4,943	2,018	2,551



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
<b>2025</b>	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
<b>Capacity (MW) *</b>	42,228	7,988	32,232	37,168	32,286	201,871	108,912
<b>Purchase/Sale (MW)</b>	-331	-90	0	2,138	0	-939	-173
<b>Load (MW)</b>	40,635	5,708	28,025	31,470	22,686	151,998	93,429
<b>Nameplate Demand Response (MW)</b>	2,327	277	3,472	873	390	8,910	4,294
<b>Active Demand Response (MW)</b>	0	0	678	0	0	0	0
<b>Reserves (%)</b>	8.8	43.2	27.4	27.7	44.0	38.1	21.0
<b>Maintenance - Peak Week (MW)</b>	**	0	0	6	0	0	0
<b>Wind Output at time of Area Peak (MW) ***</b>	1,375	560	340	280	1,727	2,018	2,620
<b>Wind Nameplate Capacity (MW)</b>	3,820	1,608	2,151	2,603	4,943	2,018	2,620



## NPCC 2021 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
<b>2026</b>	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
<b>Capacity (MW) *</b>	42,228	7,990	33,108	37,166	30,180	201,871	109,289
<b>Purchase/Sale (MW)</b>	602	0	0	2,138	0	-939	-173
<b>Load (MW)</b>	40,622	5,706	28,181	31,326	22,934	152,359	93,737
<b>Nameplate Demand Response (MW)</b>	2,629	277	3,703	873	390	8,927	4,294
<b>Active Demand Response (MW)</b>	0	0	678	0	0	0	0
<b>Reserves (%)</b>	11.9	44.9	30.6	28.3	33.3	37.7	21.0
<b>Maintenance - Peak Week (MW)</b>	**	0	0	6	459	0	0
<b>Wind Output at time of Area Peak (MW) ***</b>	1,375	569	567	371	1,695	2,018	2,693
<b>Wind Nameplate Capacity (MW)</b>	3,820	1,608	2,991	2,603	4,943	2,018	2,693