Northeast Power Coordinating Council

2020 Long Range Adequacy Overview

Approved by the RCC

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Conducted by the

NPCC CP-8 Working Group

NPCC CP-8 WORKING GROUP

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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 [1] through a multi-area probabilistic assessment for the period from 2021 to 2025, based on the data reported within the *NERC 2020 Long-Term Reliability Assessment* [2] (LTRA).

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [3] was selected by NPCC for this analysis. GE Energy Consulting was retained by the CP-8 Working Group to conduct the simulations. MARS version 3.30.1531 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's *NPCC Reliability Assessment for Summer 2020*, April 16, 2020, [4] 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 2021-2025 period, consistent with the information reported for the *NERC 2020 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.

[1] See: Directory No. 1- Section 5.2 https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories
[2] See: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[3] See: http://geenergyconsulting.com/practice-area/software-products/mars
[4] See: https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/npcc-2020-summer-assessment.pdf , Appendix VIII

Modeling Assumptions

The assumptions used in the NPCC Long Range Adequacy Overview are consistent with the data reported in *NERC 2020 Long-Term Reliability Assessment.* [5] and the following recently completed Area studies:

Area Studies Summary

New York

The Comprehensive System Planning Process (CSPP) is the New York ISO's biennial ten-year planning process comprised of four components: 1) Local Transmission Planning Process (LTPP); 2) Reliability Planning Process (RPP) and the newly-defined Short-Term Reliability Process (STRP); 3) Congestion Assessment and Resource Integration Study (CARIS); and 4) Public Policy Transmission Planning Process (PPTPP). 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 RPP consist of two evaluations:

1. The Reliability Needs Assessment (RNA). The New York ISO 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 [6] years 4 through year 10). Through this evaluation, the NYISO identifies Reliability Needs in accordance with applicable Reliability Criteria. This report is reviewed by New York ISO stakeholders and approved by the Board of Directors.
2. The Comprehensive Reliability Plan (CRP). After the RNA is complete, the New York ISO requests the submission of market-based solutions to satisfy the Reliability Need. The New York ISO 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 New York ISO 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 transmission solution to the identified need, if applicable. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the New York ISO triggers regulated solution(s) to satisfy the need. The New York ISO develops the CRP for the RNA Study Period 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.

[5] See: http://www.nerc.com/page.php?cid=4|61

[6] 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 is responsible for 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.

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 completed STAR report on October 13, 2020 and commenced the next STAR on October 15, 2020. The 2020 RNA also incorporates 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

The *2020 Reliability Needs Assessment* [7] (RNA) assesses the resource adequacy and transmission security of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTF) 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[8]")
- Transmission:
  - Provided in the 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 1800 MW of BTM solar added by 2025
- Generation Removed:
  - The last coal units at Somerset and Cayuga were deactivated in the cases
  - 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."[9] will result in approximately 1,500 MW of combustion turbine peaker capability located mainly

[7] https://www.nyiso.com/library

[8] https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/

[9] 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.

in the New York City, Hudson Valley and Long Island to be unavailable phasing in from 2023 to 2025.

The 2020 RNA has 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 are 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." 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 for this 2020 RNA indicates potential increased risks of reliability criteria violations in the future. 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 a 70% renewable energy by 2030 ("70x30 scenario").

<u>Subsequent studies, such as the 2020 RNA scenario, as well as the *Climate Change Impact and Resilience Phase II Study*,</u> build upon the findings of the 2019 CARIS scenario, and provide further insight focusing on system reliability aspects such as transmission security and resource adequacy. The 70x30 Scenario is based on the New York State Climate Leadership and Community Protection Act (CLCPA) 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), 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.

Summary of the 3rd Quarter ("Q3") 2020 STAR Summary

The Q3 STAR[10] assesses the resource adequacy and transmission security of the New York Control

[10] https://www.nyiso.com/documents/20142/16004172/2020-Q3-STAR-Report-vFinal.pdf/f836a71a-8fb7-dd24-2b6a-bfd0e739e2ec

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 RNA.

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

- 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 are identical to those identified in the 2020 Reliability Needs Assessment ("RNA"), and therefore will be addressed in the long-term Reliability Planning Process.

New England

The New England assumptions used in this overview are consistent with the data reported in the *NERC 2020 Long-Term Reliability Assessment.* [11] the *2020-2029 Forecast Report of Capacity, Energy, Loads and Transmission* (2020 CELT) [12] data and the *NPCC 2020 New England Comprehensive Review of Resource Adequacy*. [13]

ISO-New England 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 forecast are considered coincident. This demand forecast is the gross demand forecast, which is then decreased to a net forecast by subtracting the impacts as a result of conservation/energy efficiency measures and BTM PV. ISO-New England is a summer-peaking electrical power system. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected to occur.

Over the assessment period 2021 through 2025, the 50/50 New England net peak demand (gross peak demand minus behind-the-meter photovoltaic (BTM PV) resources) is expected to increase from 28,438 MW in 2021 to 29,534 MW by 2025. The 1,096 MW increase in net peak demand represents a 3.85% growth during the 5-year period. The New England net energy for load is expected to increase from 123,268 GWh in 2021 to 124,678 GWh by 2025. The 1,410 GWh increase in net energy for load represents a 1.14% growth during the study period.

[11] See: http://www.nerc.com/page.php?cid=4|61
[12] See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/
[13] See: https://www.npcc.org/library/resource-adequacy

Annually, ISO-New England 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 3,653 MW in 2021 to 4,877 MW by 2025. This represents a 1,224 MW (33.5%) increase during the study period. Meanwhile, demand resource programs are expected to grow from 3,700 MW in 2021 to 3,919 MW by 2025.

This year, for the first time, ISO-New England has included an electrification forecast in the load forecast. A 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. EV demand is forecast to be 12 MW in 2020, 34 MW in 2021.

On June 1, 2018, ISO-New England integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e. treated similar to generators). Regional DR will increase to 592 MW by 2023 and this value is assumed constant/available thru the remainder of the assessment period.

Resource additions from November 2020 through May 2022 consist mainly of solar and wind resources with approximately 100 MW of hydro resource uprates. Total capacity addition by mid-2022 amounts to approximately 177 MW.

New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM PV. Approximately 12,400 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 diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day,

Generating capacity that has been added since 2019 consists primarily of 251 MW nameplate of solar capacity. Existing certain capacity for 2021 is 30,499 MW. Approximately 40 MW of Tier 1 solar and ~ 10 MW wind capacity is projected to be added by 2021. Tier 2 capacity additions scheduled for 2021 include 255 MW of wind and solar generation. In 2022, scheduled Tier 2 capacity additions total 605 MW of wind, solar, and natural-gas-fired generation.

Resource retirements are expected to total approximately 2,570 MW by mid-2024. Notable retirements include:

Projected Retirement Date	Station Name	Approximate Summer Capacity (MW)
June 2021	Bridgeport Harbor 3	370
June 2022	Mystic 7 and Jet Pawtucket Power	551 57
June 2023	South Meadow 11 - 14	148
June 2024	Mystic 8 & 9	1,427

New England is interconnected with the three Balancing Areas (Bas) of Quebec, the Maritimes, and New York. ISO-New England takes into account the transmission transfer capability between these BAs to assure that their limits are accounted for in regional resource adequacy. ISO-New England's Forward Capacity Market methodology limits the purchase of import capacity based on these interconnection transfer limits. ISO-New England's capacity net imports are assumed to range from 1,059 MW to 1,305 MW during the 2021 to 2023 period and decrease to 82 MW by 2024 and 14 MW by 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, two significant projects remain under construction, Greater Boston and Southeastern Massachusetts and Rhode Island (SEMA/RI). The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by Dec. 2023. The SEMA/RI project is in the early stages of construction.

Ontario

The Ontario assumptions used in this study are consistent with the data reported in the *NERC 2020 Long-Term Reliability Assessment*. [14]

Over the 2021-2025 period, the Ontario peak demand is expected to increase on average by about 1.8% annually and the energy demand is to increase by about 0.6%. 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 savings, electricity price responsiveness, and increased output by distributed generation. In the near term, there is demand forecast uncertainty due to COVID-19. However, demand is expected to experience upward pressure from economic and demographic growth in the long term. Growth will also come from the EV market, the electrification of transit and the move away from carbon fuels and towards cleaner electricity.

[14] See: http://www.nerc.com/page.php?cid=4|61

Contracted wind resources amounting to 360 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.

Future capacity auctions will enable demand response, including dispatchable loads and hourly DR resources, to compete with other resources. Resources with capacity obligations are required to be available for curtailment up to their secured capacity during times of system need. The December 2019 DR Auction procured 858.6 MW for the six-month summer commitment period beginning on May 1, 2020, and 919.3 MW for the six-month winter commitment period beginning on November 1, 2020.

The Ontario IESO estimates total DERs in Ontario exceed 4,300 MW, including about 4,000 MW of contracted renewable resources. The Ontario IESO continues to collaborate with the DER community to increase coordination between the grid operator and embedded resources, directly or through integrated operations with local distribution companies with the aim to improve visibility of DERs and identify opportunities for a more coordinated operation of Ontario’s electricity system.

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. One unit at Darlington Nuclear Generating Station returned to service in May 2020 from a four-year long refurbishment outage. The retirement of Pickering Nuclear Generating Station is currently proposed to be deferred to 2024/2025, from 2022/2024. Napanee Generating Station, a 994 MW gas-fired plant, was added in March 2020. Contracted wind resources amounting to 360 MW are expected to be added to the grid in 2020.

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. Ontario has the option to receive 500 MW of capacity from Quebec for one summer before 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. Furthermore, system-backed capacity import resources will be able to participate in the future capacity auctions.

A new 400–450 km long 230 kV double-circuit transmission line is planned to come into service in Q4 2021 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid. Planning is underway to reinforce several 230 kV transmission lines by 2023 to increase the supply capability into the Central Toronto area. In the Windsor-Essex area, two projects have been initiated: development of a new switching station expected in-service in Q3 2022; and, a new approximately 50-km, double-circuit 230 kV transmission line to bring additional supply to the area by Q4 2025. In the Ottawa area, the Ontario IESO has requested work to proceed to upgrade circuits between Merivale TS and Hawthorne TS, with a planned in-service date of Q4 2022. This project will address supply capacity constraints to west Ottawa and support the deliverability of capacity imports from Québec. In Eastern Ontario, high voltage levels have been observed due to low transfer levels across the 500 kV transmission system. To mitigate the issue, two 500 kV line-connected shunt reactors will be installed with a planned in-service date of Q4 2021.

Québec

The Québec Area assumptions used in this study are consistent with the data reported in the *NERC 2020 Long-Term Reliability Assessment.* [15]

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 1,738 730 MW on winter 2020-2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings which will have an impact of 310 MW in 2020-21, 150 MW for winter 2021-2022 and then growing to 300 MW by 2026-27. Another similar program for residential customers is under development and should gradually rise from 57 MW for winter 2020-2021 to 621 MW for winter 2030-2031.The area is also expanding its existing interruptible load program for commercial buildings which will grow from 330 MW in 2020-21 to 515 MW by 2025-26. Another similar program for residential customers is under development.

The Romaine-4 unit (245 MW) was expected to be fully operational in 2021, but its commissioning is delayed to 2022. The refurbishment of the Rapide-Blanc generating station is expected to start next year. The integration of small hydro units also accounts for 41 MW of new capacity during the assessment period. For other renewable resources, about 371 MW (134 MW on-peak value) of wind capacity has been added to the system since 2018 and 54 MW (20 MW on-peak value) is expected to be in service by 2021. Additionally, 61 MW of new biomass is expected to be in service by 2022. Finally, 9.5 MW of solar resource will be in service by the end of this year. Its impact at the peak time period is not significant.

In 2019, Hydro-Québec TransÉnergie conducted a Transmission System Planning Assessment to fulfill NERC TPL-001-4 requirements. As a result, the commissioning of the second Micoua-Saguenay 735 kV line planned for 2022. This new line is currently at the permitting stage and is expected to be in service in 2022.

[15] See: http://www.nerc.com/page.php?cid=4|61

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 demand 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 loads forecasted by the individual sub-areas. The aggregated growth rates of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the Long Range Adequacy Overview (LRAO) assessment period. The five-year summer growth rate starting in year 2020 is 5.7% and for winter starting in winter of 2020/21 is 1.0%. This translates to compound average growth rates of 1.1% in summer and 0.2% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 3.2% during the 5-year assessment period for an average growth of 0.6% per year. Rural to metropolitan population migration and the introduction of split phase heat pump technology to areas traditionally heated by fossil fuels has created load growth in Prince Edward Island that has outpaced load growth in the rest of the Maritimes Area in recent years. It is expected that these effects will level off in the future.

Plans to develop up to 120 MW by 2029/2030 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 assessment period in the Maritimes Area, annual amounts for summer peak demand reductions associated with Energy Efficiency and Conservation programs rise from 20 MW to 112 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 299 MW.

The current amount of Distributed Energy Resources (DERs) in the Maritimes Area is currently insignificant at about 29 MW (in winter). During the five-year assessment period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 76 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges such as ramping and light load conditions will be considered, and mitigation techniques investigated.

The DER capacity in New Brunswick is currently around 1 MW. After a 1.8 MW installation 2021, New Brunswick has no future projections to report although DER could increase rapidly in future years and potentially impact operation of the distribution system. Studies by New Brunswick Power in conjunction with Siemens are underway to determine the impact of large scale DER installed on the system. This will include examination of the impacts of controllable solar installations and battery storage at the distribution level operating in conjunction with controllable demand response to shift electric heat and electric water heater loads during peak periods. DER is expected to form a significant portion of New Brunswick Power's DSM initiatives. 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 NPCC 2020 LRAO purposes.

Prince Edward Island and Maine have not reported any DER installations.

Confirmed generation retirements includes two units of oil based thermal generating capacity in Prince Edward Island totaling 17.6 MW, four small diesel fired thermal generators totaling 7 MW and one biomass generator of 37 MW in Northern Maine as they reached end of life. Three additional units of oil based thermal generating capacity totaling 42.8 MW are expected to retire in Prince Edward Island in the 2022 to 2023 time-frame. Nova Scotia will retire a 150 MW (nameplate) coal fueled generator in 2021 provided capacity from the Muskrat Falls hydro-electricity project in the Canadian province of Newfoundland and Labrador is available to completely offset its removal.

Small amounts of new generation capacity are being installed to introduce alternative renewable energy resources into the capacity mix. Except for hydro generation, Renewable Electricity Standards (RES) have led to the development of substantially more wind generation capacity than any other renewable generation type. In Nova Scotia, the RES target for 2020 increased from 25-40% of energy sales from renewable resources with the expectation that the incremental renewable requirements would largely be met by the energy import from the Muskrat Falls hydro project; however, due to COVID-19 related construction delays at Muskrat Falls, the RES targets and timelines are currently being revised. Currently, RES energy is provided primarily by wind generation, hydro, and biomass. For wind capacity, the Maritimes Area applies year-round calculated equivalent firm capacities of 22% (New Brunswick), 19% (Nova Scotia), 15% (Prince Edward Island), and 40% (Maine) of nameplate.

Construction of a 475 MW +/-200 kV HVDC undersea cable link (Maritime Link) between Newfoundland and Labrador and NS 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 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 New Brunswick area.

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 2003 – 2004 load shape has been 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:

- ✓ a 2002/03 load shape representative of a winter weather pattern with a typical expectation of cold days; and,
- ✓ a 2003/04 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 2003/04 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 that the 2003/04 load shape assumption be used again 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, 2003, and 2004. January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2003 and 2004 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 2003 and 2004 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 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 2019, 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 2019, 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 2021)

Area	Per-Unit Variation in Load						
HQ	1.086	1.086	1.043	1.000	0.959	0.916	0.911
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.071	1.033	0.985	0.963	0.935	0.865	0.800
NY	1.122	1.078	1.037	1.000	0.967	0.938	0.912
ON	1.057	1.041	1.021	1.000	0.976	0.948	0.920
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 2021)

Area	Per-Unit Variation in Load						
HQ	1.069	1.069	1.035	1.000	0.968	0.939	0.911
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.234	1.109	1.008	0.920	0.900	0.856	0.851
NY	1.142	1.099	1.047	0.990	0.926	0.860	0.800
ON	1.143	1.099	1.050	1.000	0.948	0.896	0.852
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

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. [16]

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 2021 to 2025. 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.

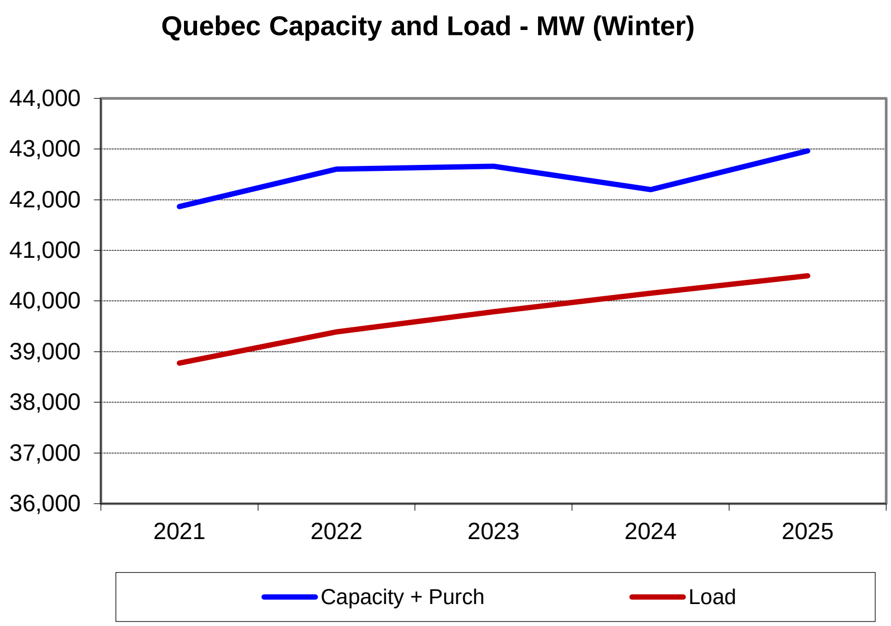

Figure 1 – Quebec Winter Capacity and Load

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[16] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

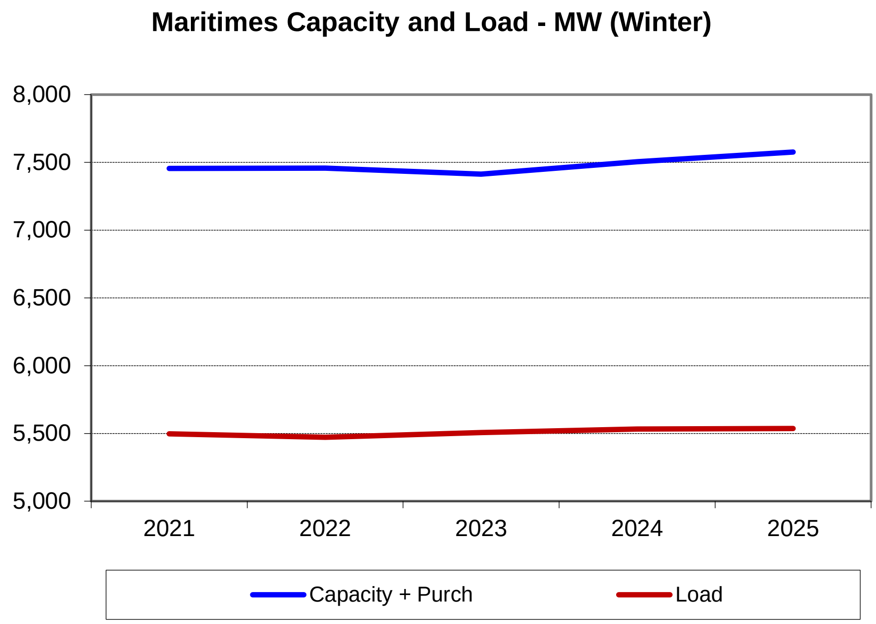


Figure 2 – Maritimes Winter Capacity and Load

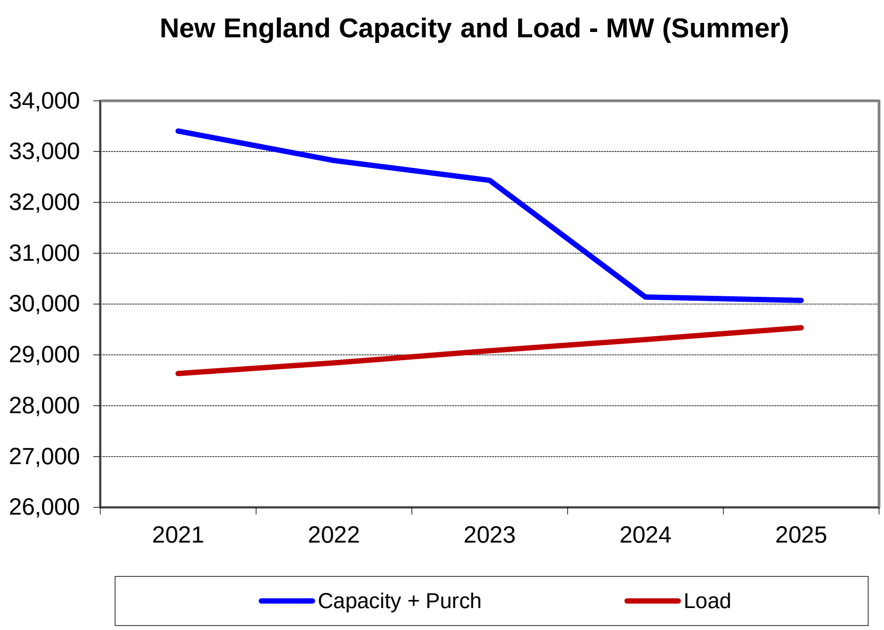


Figure 3 – New England Summer Capacity and Load

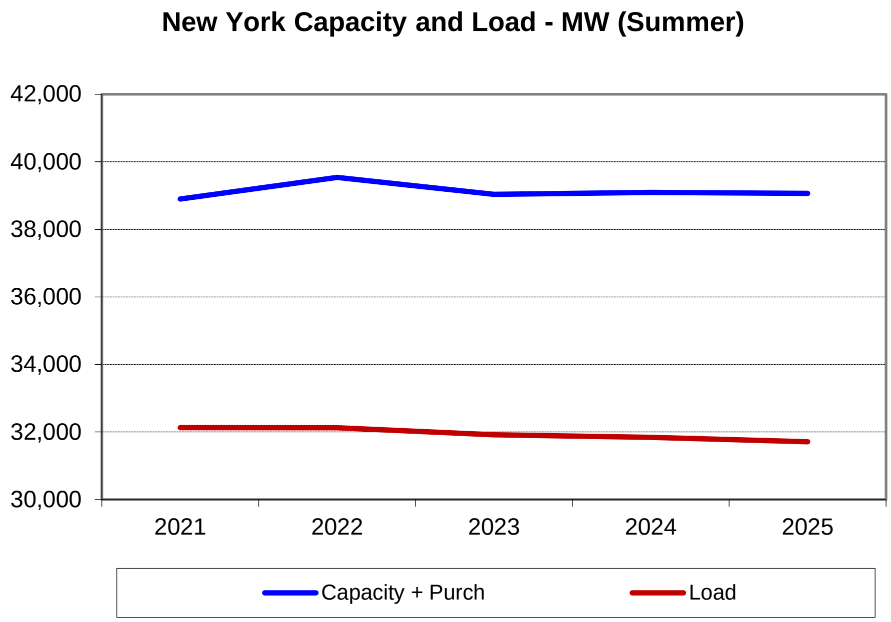


Figure 4 – New York Summer Capacity and Load

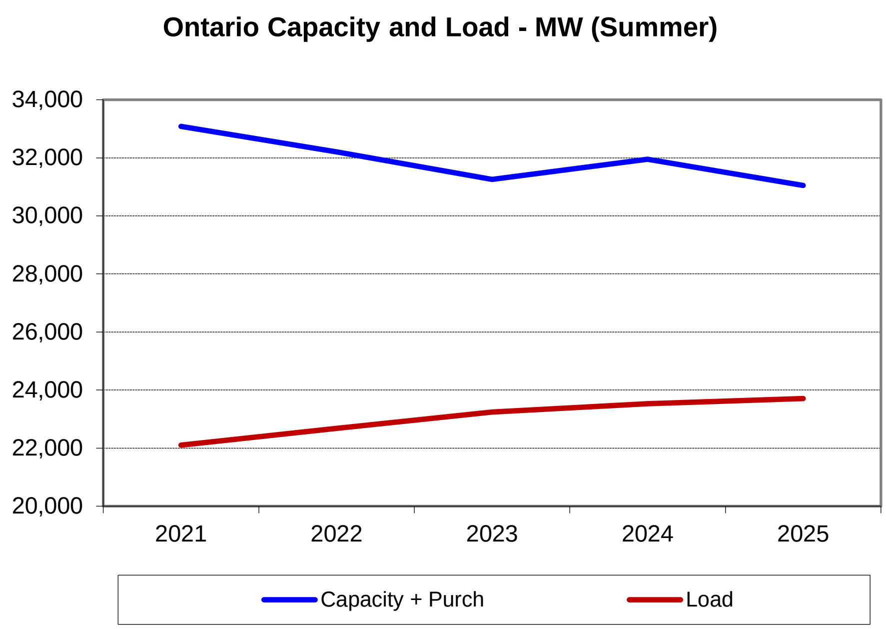


Figure 5 – Ontario Summer Capacity and Load

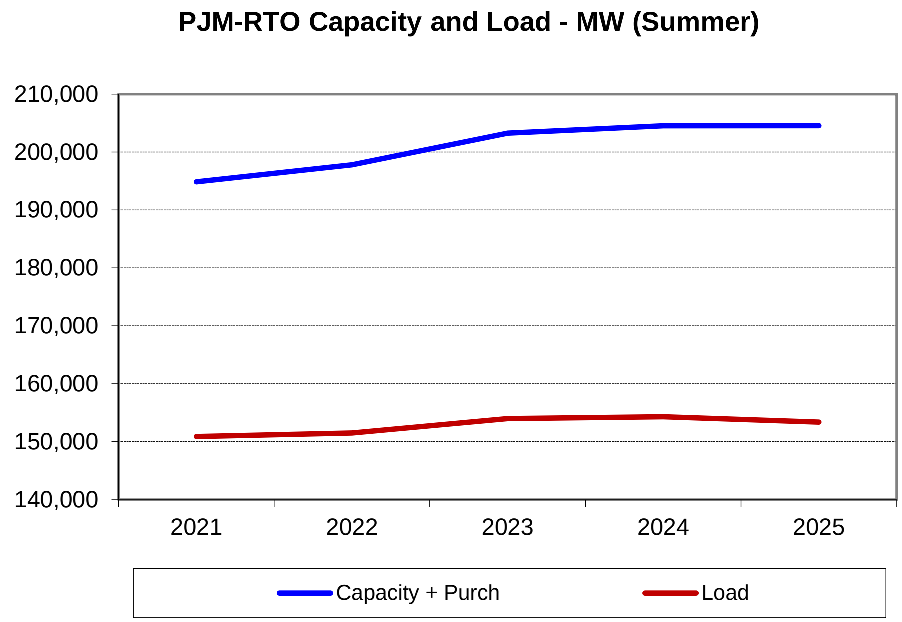
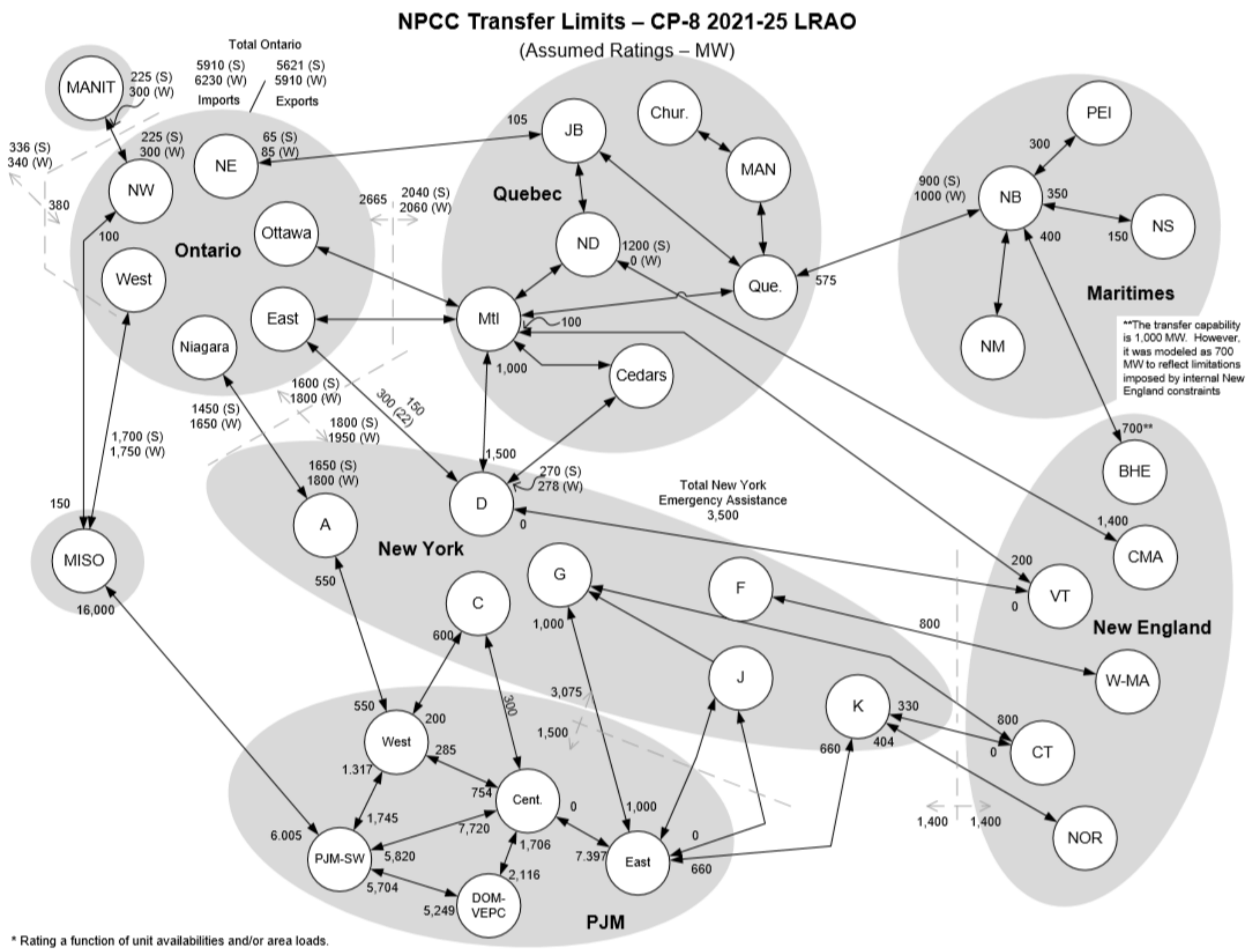


Figure 6 – PJM-RTO Summer Capacity and Load

Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2021 to 2025.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York. [17]

Figure 7 - Assumed Transfer Limits

[17] See: http://www.oasis.oati.com/HQT/HQTdocs/2014-04_DEN_et_CORN-version_finale_en.pdf

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		

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 2021 Load Relief Assumptions - MW

Actions	HQ (Jan)	MT (Jan)	NE (Aug)	NY (Aug)	ON (Aug)
1. Curtail Load	1,732	-	-	-	-
Appeals	-	-	-	-	1% of load
RT-DR/SCR/EDRP	-	-	-	873[18]	-
SCR Load /Man. Volt. Red.	-	-	-	0.21% of load	-
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction	250	-	263	1.0% of load	1.3% of load
Interruptible Loads	-	277	-	207	
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	-
Appeals/Curtailments	-	-	-	-	-

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.

[18] Derated value shown accounts for assumed availability.

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.

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 2021 are summarized in Table 3 and Figure 8.

Table 3
PJM and MISO 2021 Assumptions [19]

	PJM	MISO
Peak Load (MW)	150,905	95,223
Peak Month	July	August
Assumed Capacity (MW)	194,192	109,061
Purchase/Sale (MW)	671	-1,501
Reserve (%)	35	18
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	8,955	4,553
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
Load Forecast Uncertainty	+/- 13.5%, 9.0%, 4.5%	+/- 11.3%, 7.6%, 3.8%

[19] 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/

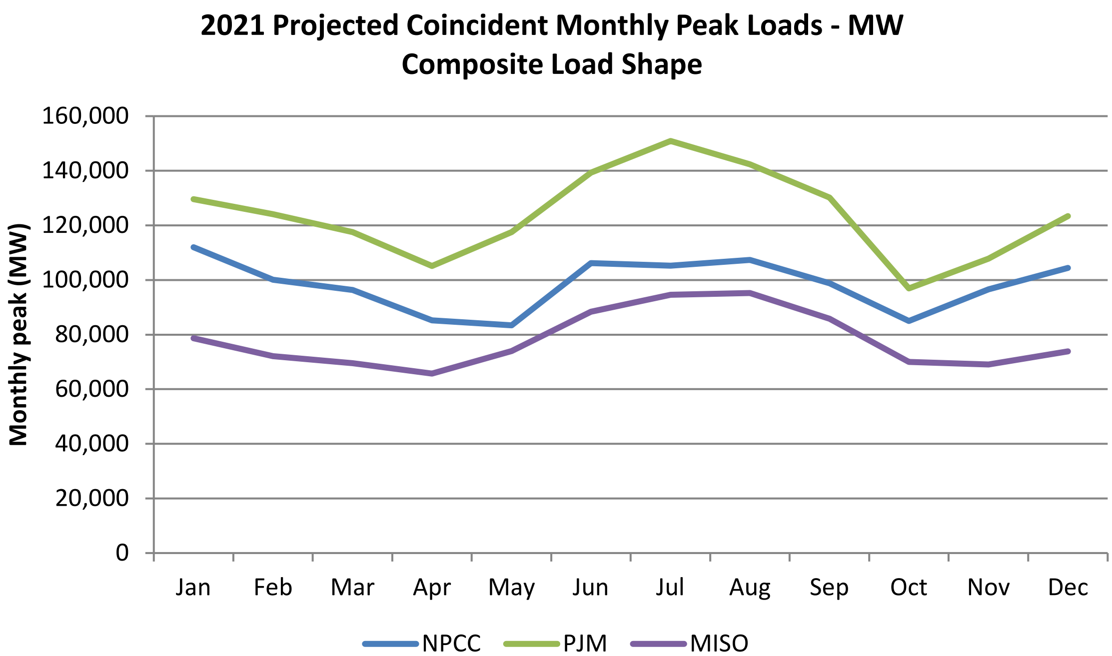


Figure 8 – 2021 Projected Monthly Expected Peak Loads for NPCC, PJM and MISO

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 2020. Load Forecast Uncertainty was modeled consistent with recent PJM planning models considering seven load levels, each with an associated probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years that the model is based on, sampling size, and how many years in the future for which the load forecast is being derived.

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

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

Results

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2021-2025 period.

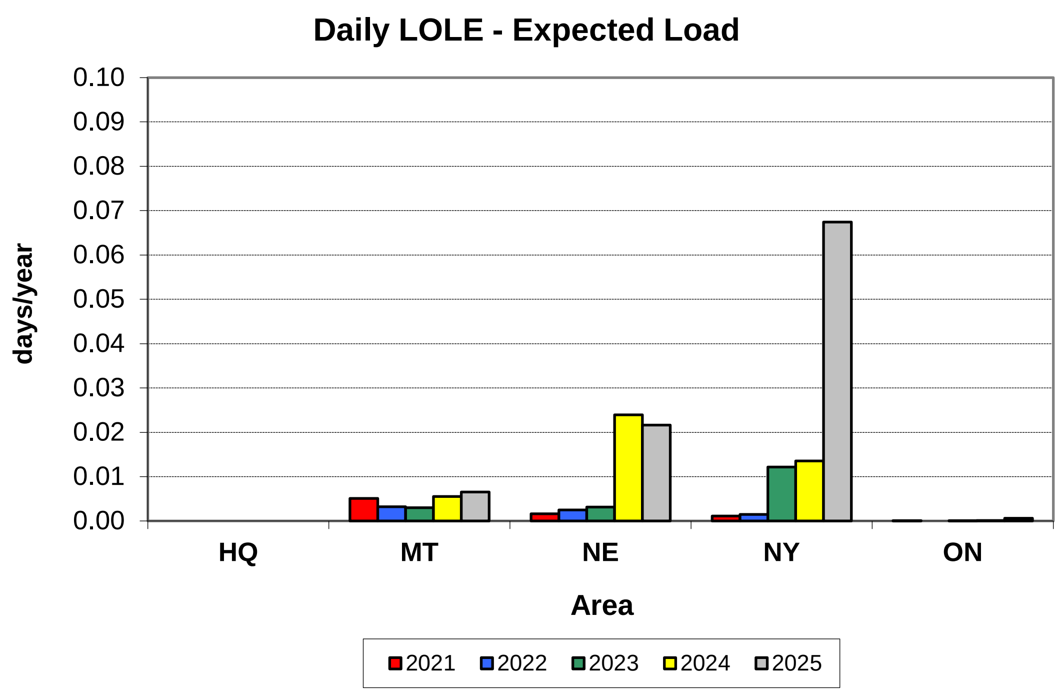


Figure 9(a) - Estimated Annual NPCC Area LOLE (2021 – 2025)

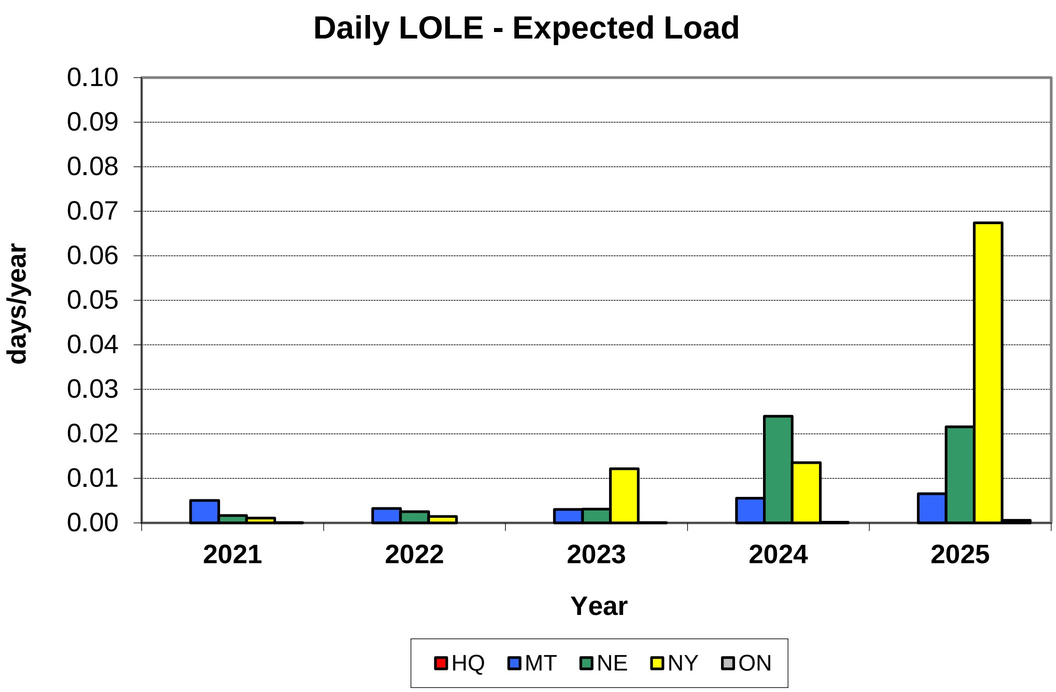


Figure 9(b) - Estimated Annual NPCC Area LOLE (2021– 2025)

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2021-2025 period.

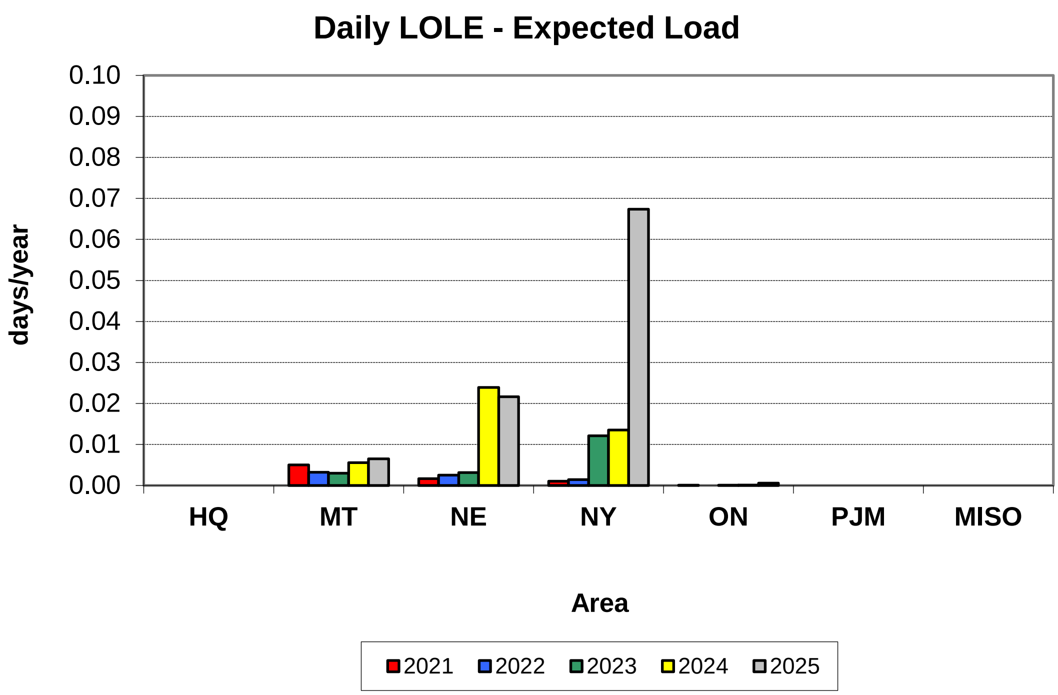


Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2021 – 2025)

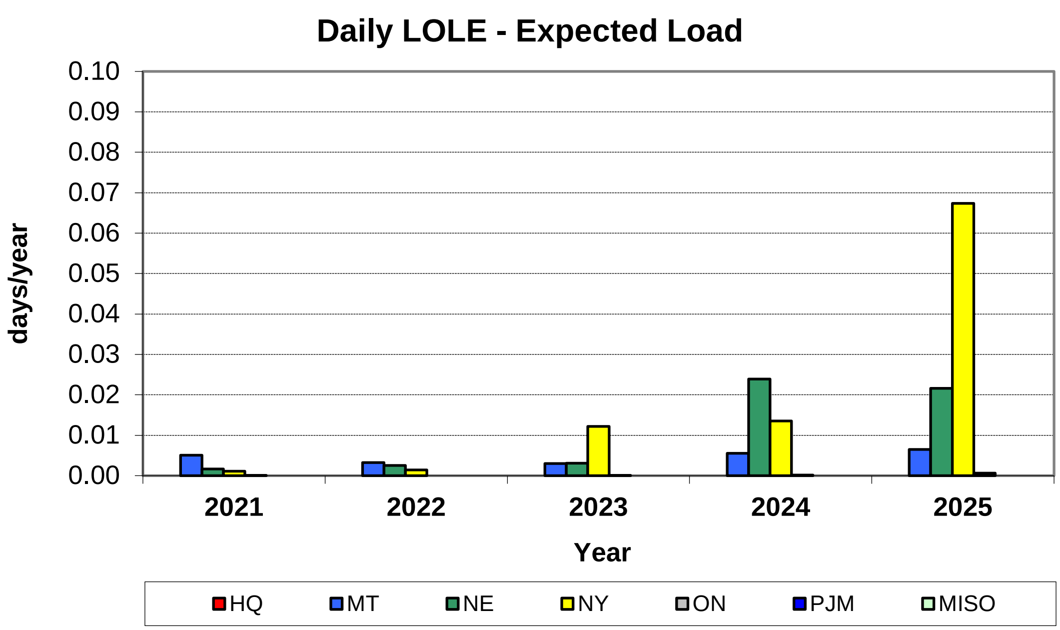


Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region's LOLE (2021 – 2025)

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2021-2025 period.

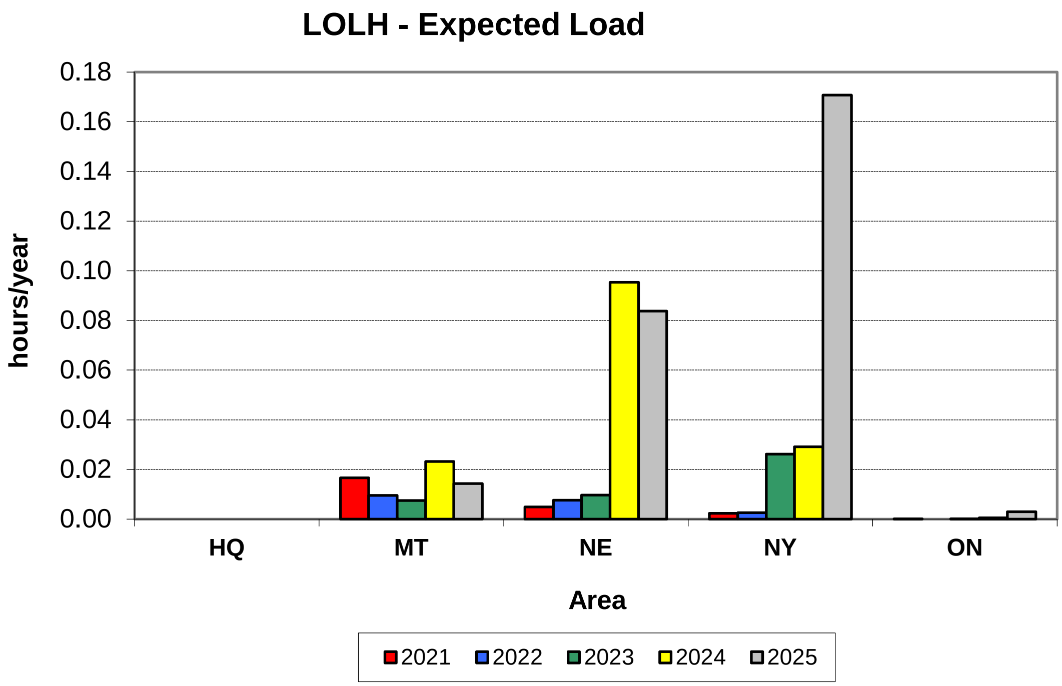


Figure 10(a) - Estimated Annual NPCC Area LOLH (2021 – 2025)

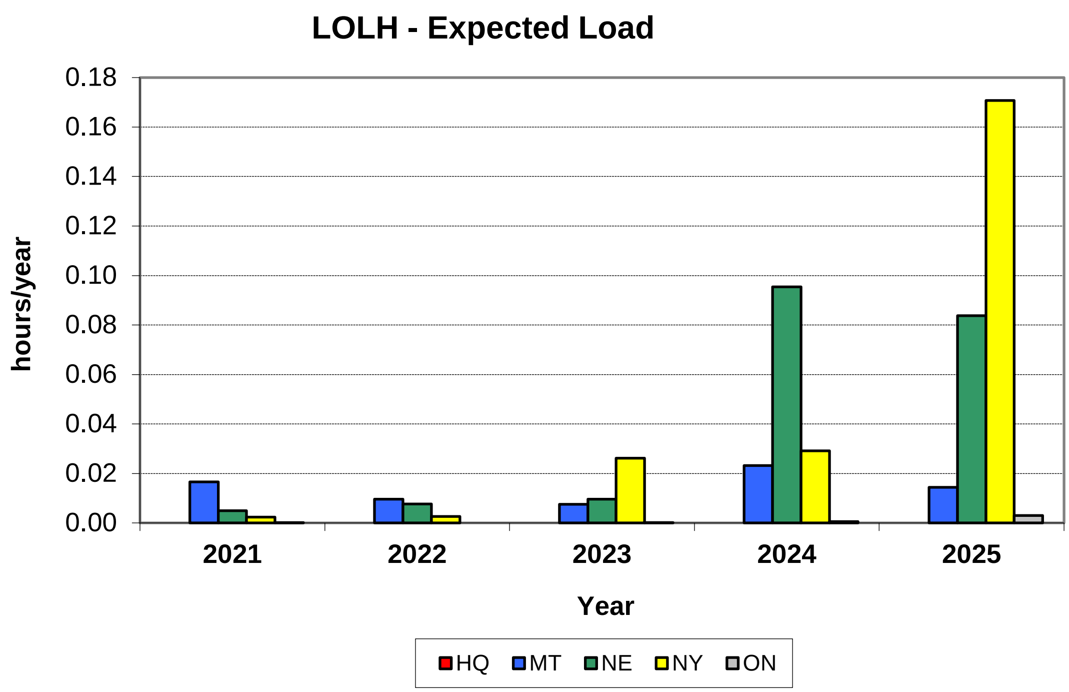


Figure 10(b) - Estimated Annual NPCC Area LOLH (2021 – 2025)

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2021-2025 period.

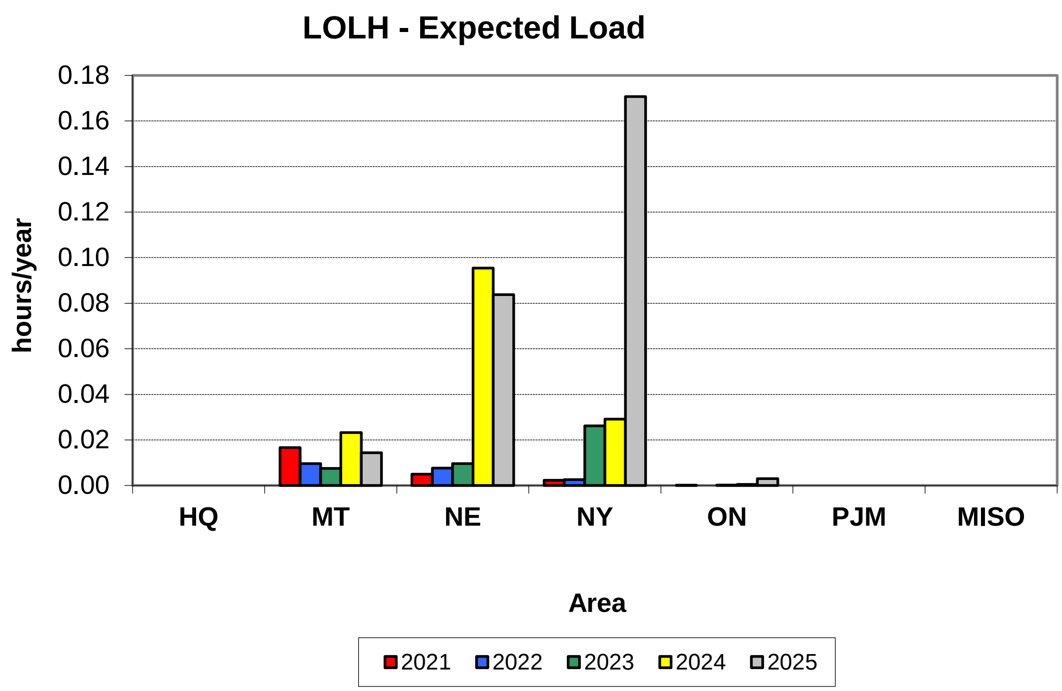


Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2021 – 2025)

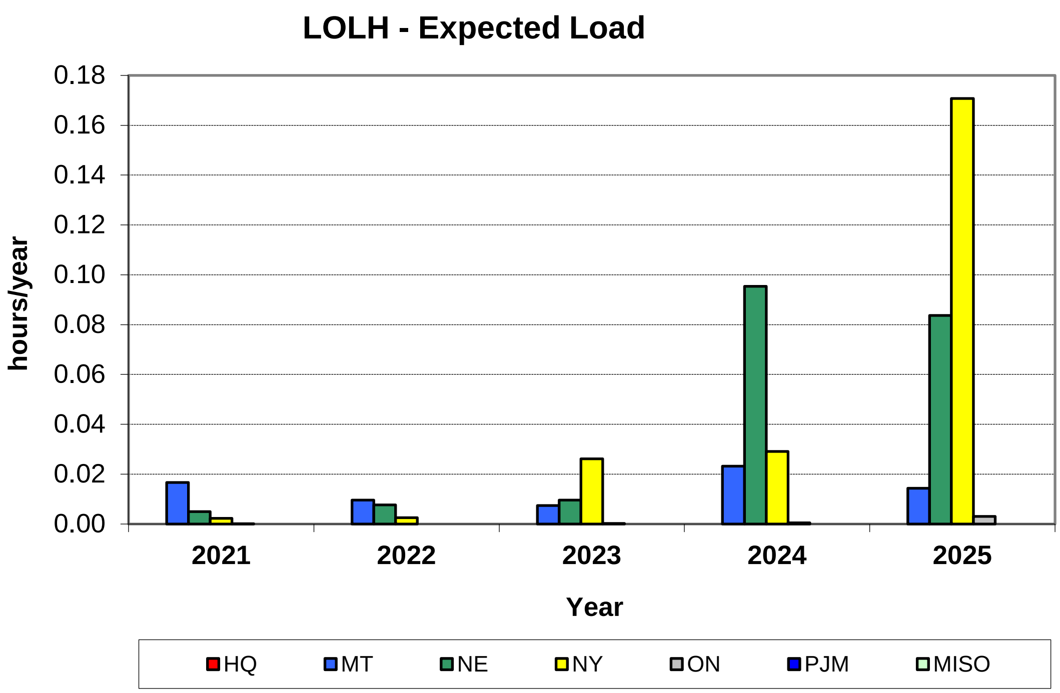


Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2021 – 2025)

Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2021-2025 period.

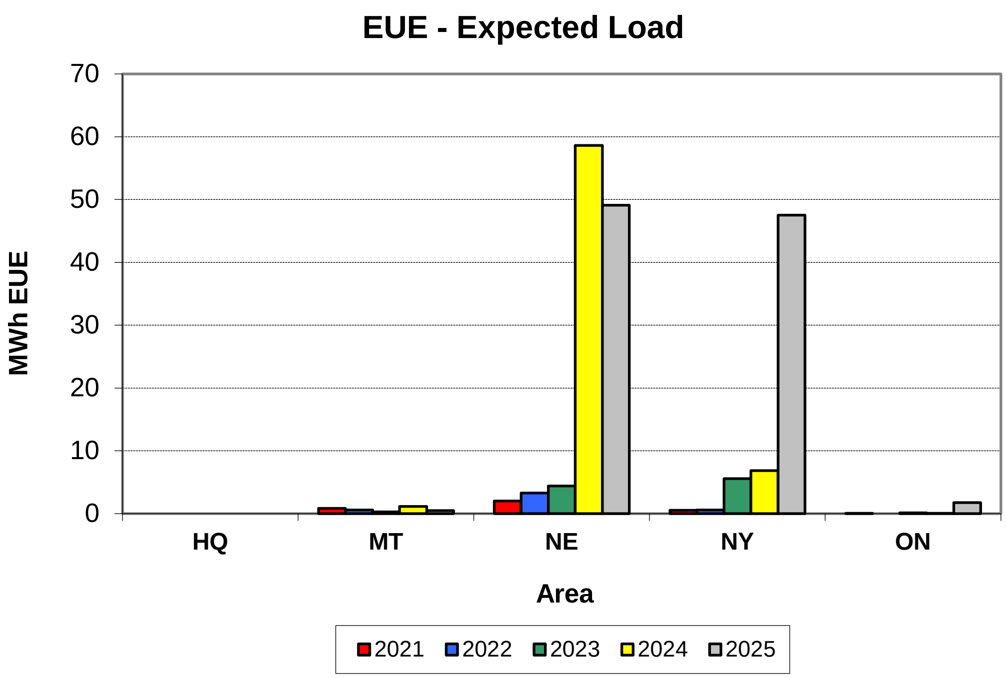


Figure 11(a) - Estimated Annual NPCC Area EUE (2021 – 2025)

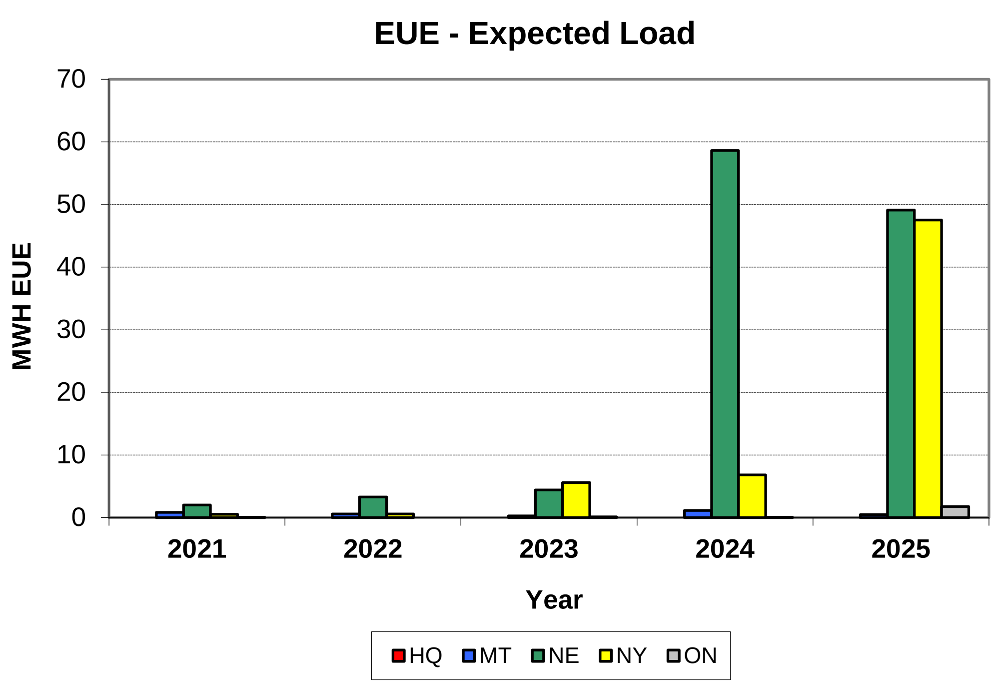


Figure 11(b) – Estimated Annual NPCC Area LOLH (2021 – 2025)

Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2021-2025 period.

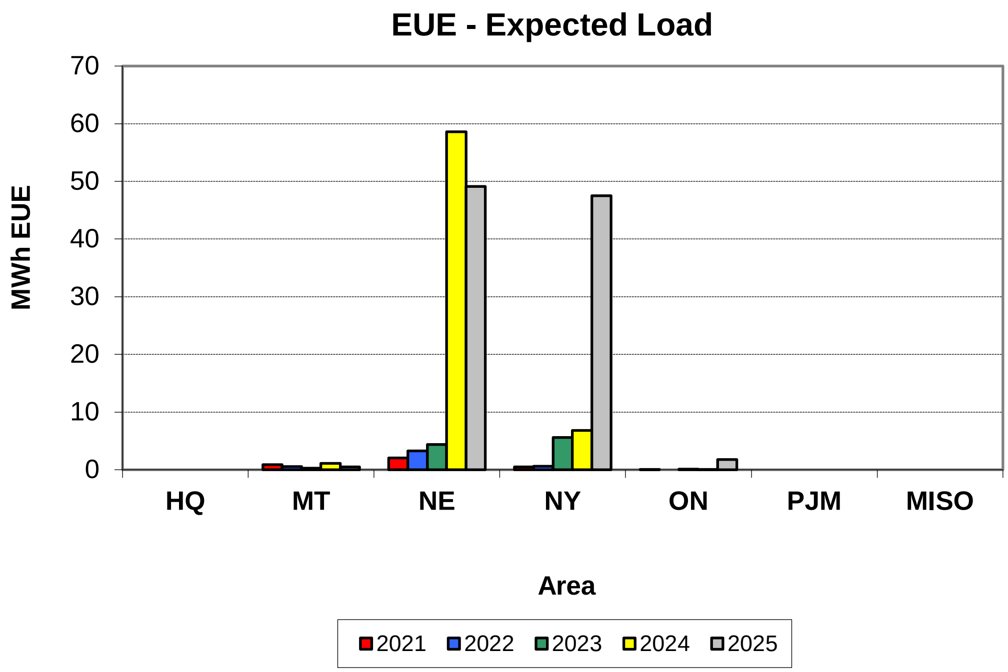


Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2021 – 2025)

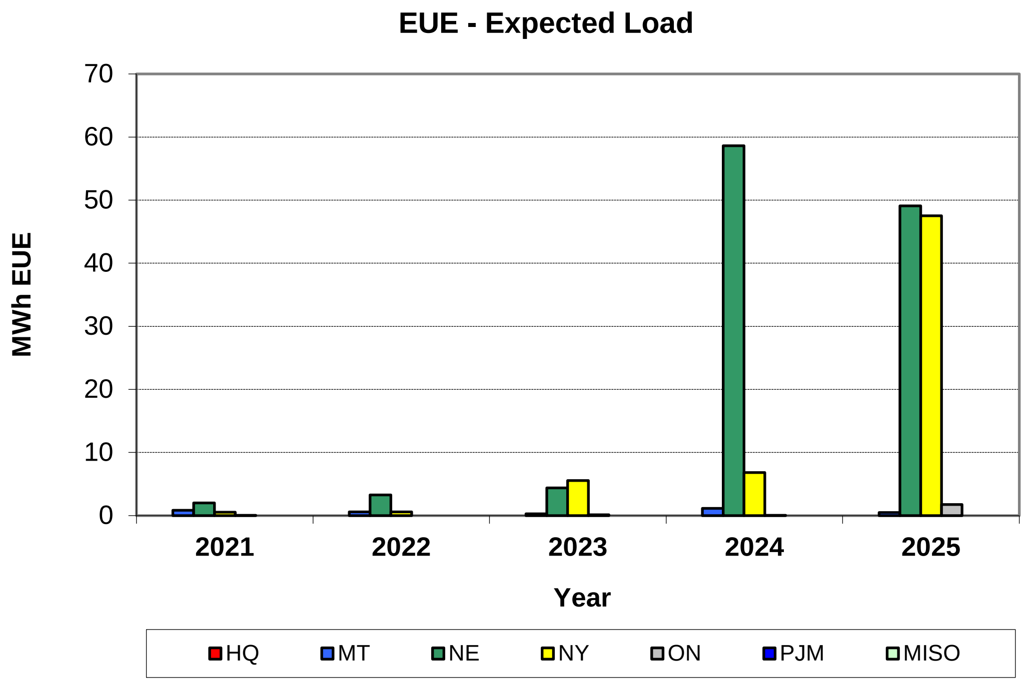


Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2021 – 2025)

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 2020 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 3% of the corresponding sum of the NPCC Areas annual energy forecasts.

Table 4 –Comparison of Energies Modeled (Annual GWh)

Year	2021	2022	2023	2024	2025
Québec					
MARS	194,004	194,679	195,102	199,365	197,848
2020 LTRA	192,188	191,760	191,760	195,695	196,571
MARS - LTRA	1,816	2,918	3,342	3,670	1,277
%(MARS-LTRA)/LTRA	0.94%	1.52%	1.74%	1.88%	0.65%
Maritimes					
MARS	29,035	28,525	28,524	28,952	28,981
2020 LTRA	27,787	27,976	28,360	28,507	28,509
MARS - LTRA	1,248	549	164	446	472
%(MARS-LTRA)/LTRA	4.49%	1.96%	0.58%	1.56%	1.66%
New England					
MARS	136,955	138,230	139,510	140,890	141,507
2020 LTRA	123,270	123,688	123,864	124,539	124,678
MARS - LTRA	13,685	14,542	15,646	16,351	16,829
%(MARS-LTRA)/LTRA	11.10%	11.76%	12.63%	13.13%	13.50%
New York					
MARS	149,975	151,149	149,624	148,952	148,204
2020 LTRA	150,627	152,114	150,544	149,904	149,167
MARS - LTRA	-652	-965	-920	-952	-963
%(MARS-LTRA)/LTRA	-0.43%	-0.63%	-0.61%	-0.64%	-0.65%
Ontario					
MARS	134,408	134,646	134,883	137,228	137,929
2020 LTRA	134,320	134,556	134,793	137,135	137,836
MARS - LTRA	89	90	91	93	93
%(MARS-LTRA)/LTRA	0.07%	0.07%	0.07%	0.07%	0.07%

Year	2021	2022	2023	2024	2025
NPCC					
MARS	644,377	647,228	647,644	655,388	654,469
2020 LTRA	628,191	630,094	629,321	635,780	636,761
MARS - LTRA	16,186	17,134	18,323	19,608	17,708
%(MARS-LTRA)/LTRA	2.58%	2.72%	2.91%	3.08%	2.78%

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 expected load level.

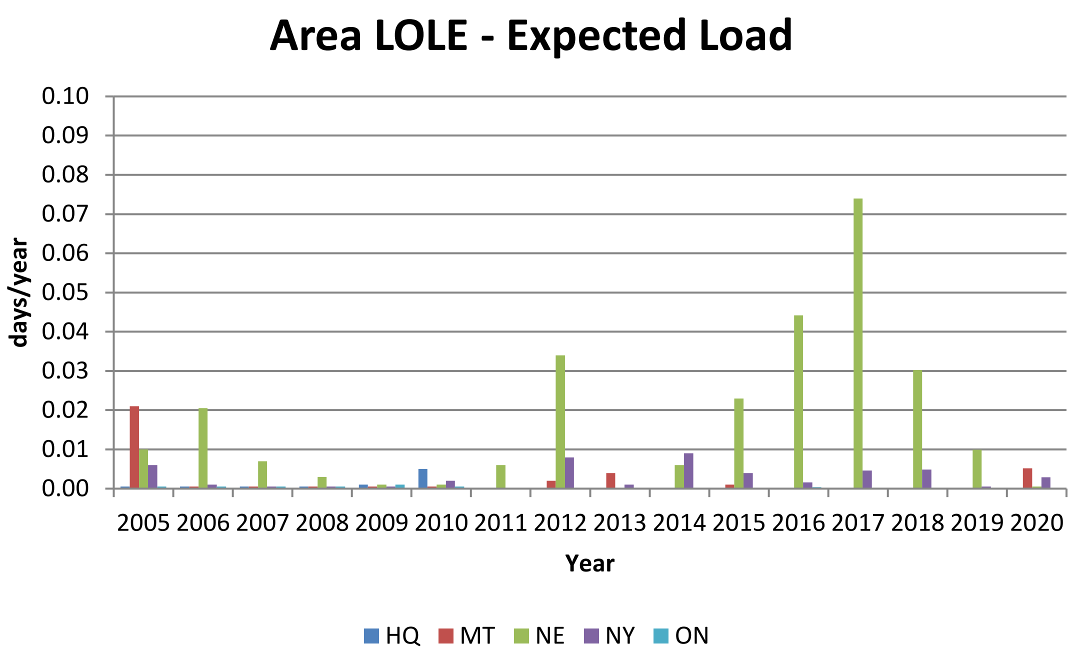


Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

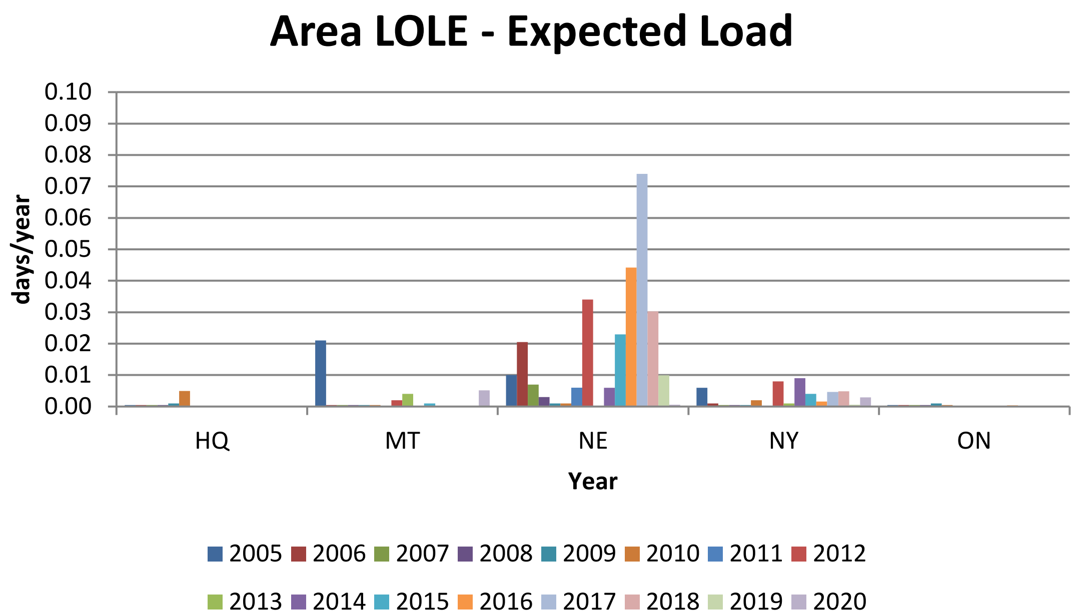


Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

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 2021 – 2025.

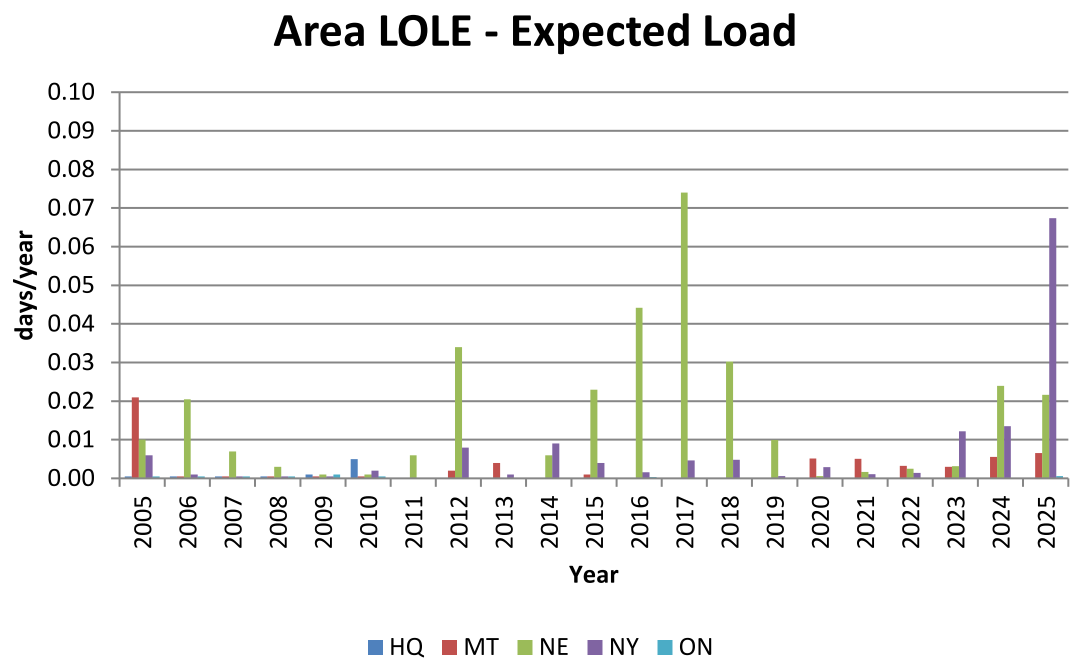


Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

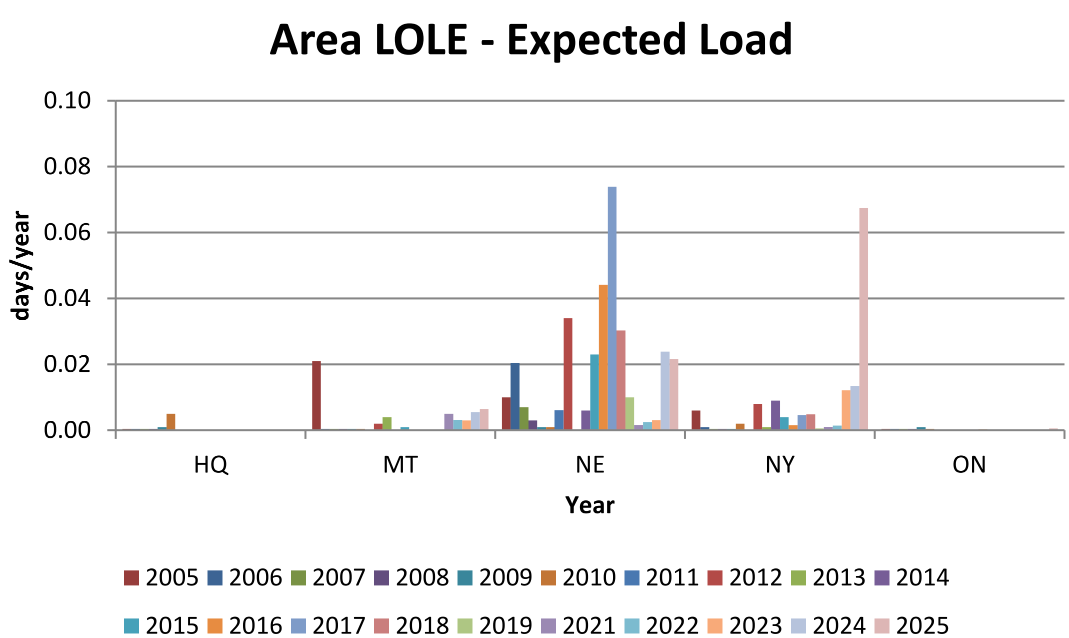


Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

Appendix A: Objective and Scope of Work

1. Objective

Extend the G.E. MARS database developed for the near-term seasonal assessments for the years 2021 – 2025, 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 2021 - 2025 time period will be modeled.

The resultant long-range G.E. MARS model will reflect NPCC Area and neighboring Regional plans proposed to meet their respective resource adequacy planning criteria, including considering the potential effects of proposed market mechanism.

2. Scope

The CP-8 Working Group's G.E. MARS long-range database will be used to develop a model suitable for the years 2021 - 2025, consistent with the NPCC Area data reported in 2020 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.

The annual Loss of Load Expectation (LOLE) will be estimated for each NPCC Area and neighboring Regions for each calendar year. In addition, Loss of Load Hours (LOLH) and Expected Unserved Energy will also be similarly estimated for the NPCC Areas, consistent with related NERC Reliability Assessment Subcommittee probabilistic analyses requirements.

3. Schedule

A report summarizing the results will be approved no later than December 1, 2020.

Appendix B: Modeled Capacity and Load

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2021	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	41,694	7,523	32,100	37,273	33,082	194,192	109,061
Purchase/Sale (MW)	171	-69	1,305	1,626	0	671	-1,501
Load (MW)	38,775	5,496	28,634	32,129	22,103	150,905	95,223
Nameplate Demand Response (MW)	1,982	277	3,654	873	359	8,955	4,553
Active Demand Response (MW)	0	0	654	0	0	0	0
Reserves (%)	13.1	40.7	29.4	23.8	51.3	35.1	17.7
Maintenance - Peak Week (MW)	**	10	0	0	765	0	0
Wind Output at time of Area Peak (MW) ***	1,354	596	183	296	790	1,809	1,524
Wind Nameplate Capacity (MW)	3,778	1,149	1,081	1,739	3,636	1,809	1,524

* 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; [20] Ontario utilizes random draws using a probability density function during the Monte Carlo simulation.

[20] 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.

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2022	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,353	7,523	31,637	37,820	32,204	196,564	109,371
Purchase/Sale (MW)	248	-66	1,188	1,718	0	1,218	-2,048
Load (MW)	39,392	5,471	28,843	32,128	22,677	151,532	95,484
Nameplate Demand Response (MW)	1,982	277	3,984	873	359	9,036	4,553
Active Demand Response (MW)	0	0	681	0	0	0	0
Reserves (%)	13.2	41.4	27.6	25.8	43.6	36.5	17.2
Maintenance - Peak Week (MW)	**	0	0	0	525	0	0
Wind Output at time of Area Peak (MW) ***	1,371	601	185	452	835	1,896	1,570
Wind Nameplate Capacity (MW)	3,826	1,169	1,081	2,285	3,636	1,896	1,570

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2023	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,330	7,562	31,375	37,341	31,253	202,053	109,695
Purchase/Sale (MW)	330	-149	1,059	1,696	0	1,218	-2,048
Load (MW)	39,790	5,506	29,083	31,918	23,248	153,997	95,755
Nameplate Demand Response (MW)	1,977	277	4,302	873	359	9,067	4,553
Active Demand Response (MW)	0	0	592	0	0	0	0
Reserves (%)	12.2	39.7	26.3	25.0	36.0	37.9	17.2
Maintenance - Peak Week (MW)	**	10	0	268	868	0	0
Wind Output at time of Area Peak (MW) ***	1,371	600	185	472	1,174	1,896	1,618
Wind Nameplate Capacity (MW)	3,826	1,209	1,081	2,385	3,636	1,896	1,618

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2024	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,341	7,576	29,958	37,333	31,956	203,324	110,076
Purchase/Sale (MW)	-141	-72	82	1,756	0	1,218	-2,048
Load (MW)	40,156	5,533	29,303	31,838	23,535	154,320	96,075
Nameplate Demand Response (MW)	2,159	277	4,599	873	277	9,125	4,553
Active Demand Response (MW)	0	0	592	0	0	0	0
Reserves (%)	10.5	40.6	18.6	25.5	37.0	38.5	17.2
Maintenance - Peak Week (MW)	**	0	0	268	490	0	0
Wind Output at time of Area Peak (MW) ***	1,371	484	185	292	1,150	1,896	1,667
Wind Nameplate Capacity (MW)	3,826	1,229	1,081	2,385	3,636	1,896	1,667

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2025	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,362	7,576	29,958	37,312	31,048	203,337	110,407
Purchase/Sale (MW)	602	0	14	1,756	0	1,218	-2,048
Load (MW)	40,498	5,536	29,534	31,711	23,708	153,374	96,352
Nameplate Demand Response (MW)	2,525	277	4,878	873	277	9,172	4,553
Active Demand Response (MW)	0	0	592	0	0	0	0
Reserves (%)	12.3	41.8	18.3	26.0	32.1	39.3	17.2
Maintenance - Peak Week (MW)	**	10	0	845	436	0	0
Wind Output at time of Area Peak (MW) ***	1,371	487	185	293	754	1,896	1,716
Wind Nameplate Capacity (MW)	3,826	1,229	1,081	2,385	3,636	1,896	1,716