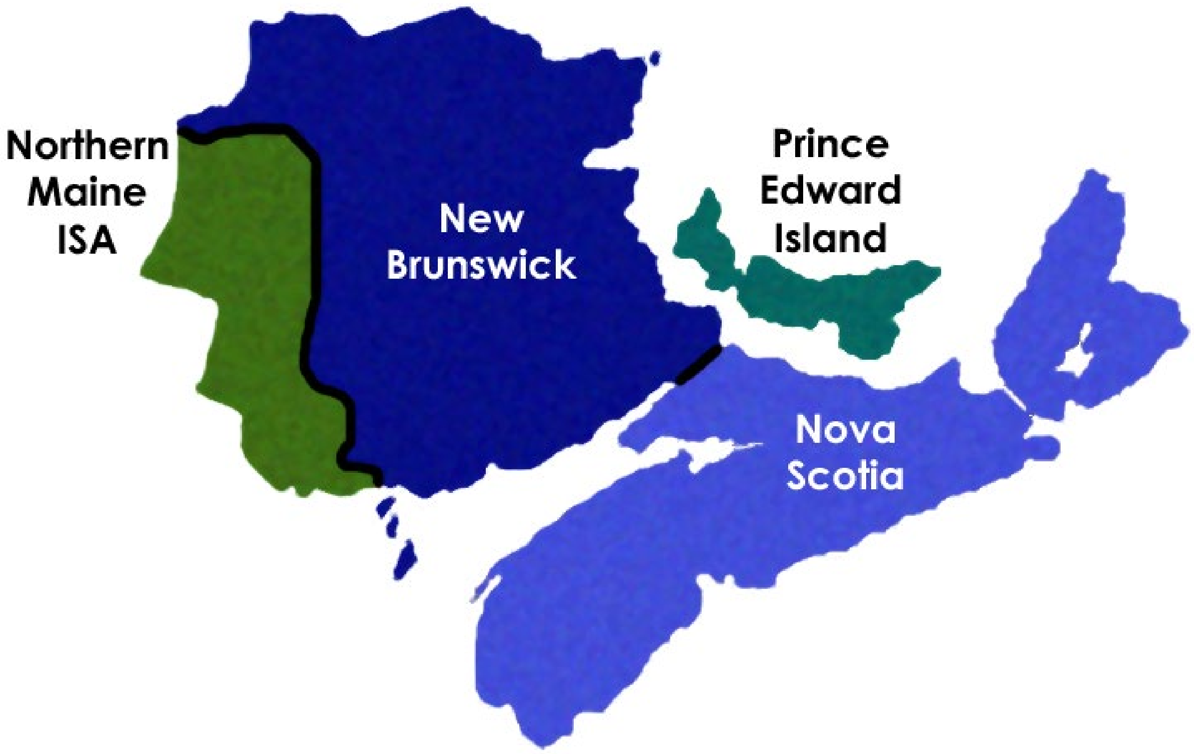
NPCC
2022 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY



NEW BRUNSWICK POWER CORP.
NOVA SCOTIA POWER INCORPORATED
MARITIME ELECTRIC COMPANY, LIMITED
NORTHERN MAINE ISA, INC.

Approved by the RCC

December 6, 2022

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EXECUTIVE SUMMARY

The 2022 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2023 through December 2027, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in the *NPCC Regional Reliability Directory #1 Appendix D (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2019 and approved by the RCC on December 3, 2019.

The NPCC resource adequacy criterion of a Loss of Load Expectation (LOLE) of not more than 0.1 days per year of firm load disconnections is not exceeded by the Maritimes Area for all years covered by this review. The Maritimes Area LOLE during the review period varies between 0.002 to 0.012 days/year for the base case forecast. The Maritimes Area is also shown to adhere to its own 20% reserve criterion in all years covered by this review, with minimum reserve levels varying between 32% to 35% for the base case forecast.

Sensitivity analyses were performed to determine the LOLE impacts due to high load growth, 50% wind derate for all hours, and removing all external tie benefits. The Maritimes Area is shown to meet the NPCC resource adequacy criterion in all years for each of these sensitivities.

Table 1 provides a summary of the major assumptions of this review.

Table 1: Summary of Major Assumptions

MAJOR ASSUMPTIONS	
Load Forecast	2022
Load and Wind Shape	2017
Resource Adequacy Criterion	Loss of Load Expectation not more than 0.1 days/year
Maritimes Reserve Criterion	20% of peak firm load
Interconnection Benefits	300 MW
Area Purchases/Sales (June through May yearly)	Firm Sales: 2022/23 149 MW 2023/24 72 MW 2024/25 90 MW 2025/26 122 MW Firm Purchases: 153 MW from Newfoundland and Labrador (starting June 2022) and 85 MW (starting December 2023).
Maritime Link Project	June 2022: 153 MW of purchases from Newfoundland and Labrador to Nova Scotia. Dec. 2023: 85 MW of additional purchases from Newfoundland and Labrador to Nova Scotia.

Table 2 provides a complete summary of LOLE results, including the base case and each of the sensitivities performed for this review.

Table 2: Summary of LOLE Results

Year	Base Case LOLE	High Load Growth LOLE	50%Wind Derate LOLE	No Tie Benefits LOLE
	days/year	days/year	days/year	days/year
2023	0.011	0.011	0.022	0.049
2024	0.012	0.016	0.027	0.034
2025	0.003	0.006	0.008	0.021
2026	0.003	0.009	0.008	0.018
2027	0.002	0.009	0.006	0.014

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1.0 INTRODUCTION

The 2022 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2023 through December 2027, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2019 and approved by the RCC on December 3, 2019.

The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM). New Brunswick Power (NB Power) is the Reliability Coordinator for the Maritimes Area.

Table 3 provides a comparison of the load and resource forecasts in the 2022 and 2019 reviews. The coincident peak demand forecast for 2023 is 5,583 MW, which is marginally lower to 5,620 MW forecast in the 2019 Comprehensive Review. Demand shifting and energy efficiency programs are expected to reduce peak demand in the Maritimes Area by 93 MW to 289 MW during the 2022 Comprehensive Review period. The average annual demand growth over the period of this review is 0.49% as compared to -0.22% average demand growth forecast in the 2019 review. A comparison of load forecasts is shown in Figure 1.

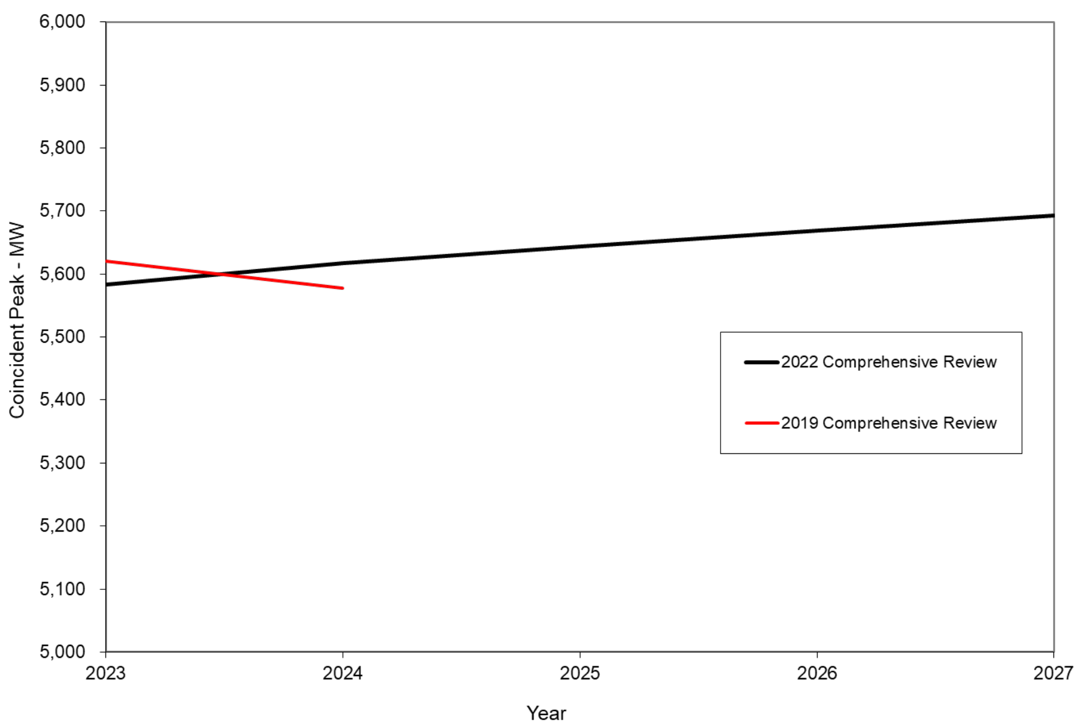
In addition to installed capacity, the resource forecast included in Table 3 incorporates external purchases and/or sales (as additions or reductions to the forecast respectively), tie benefits from neighbouring utilities, and projections of on-peak wind production (reflecting both capacity changes as well as a 2017 wind shape for both 2022 and 2019 Comprehensive Reviews).

Table 3: Comparison of Load and Resource Forecasts

Winter Peak (Month of January)	2022 Review Load MW	2019 Review Load MW	2022 Review Resources MW*	2019 Review Resources MW*
2023	5,583	5,620	6,973	6,990
2024	5,617	5,577	7,064	7,139
2025	5,643	N/A	7,195	N/A
2026	5,669	N/A	7,207	N/A
2027	5,693	N/A	7,293	N/A
Five Year Period	**2023–2027**	**2020–2024**		
Annual Average Growth Rate	0.49%	-0.22%		

* Forecast capacity incorporates all known firm purchases/sales with neighboring Areas and includes forecast wind generation production coincident with the peak load.

Figure 1: Comparison of Load Forecasts



2.0 RESOURCE ADEQUACY CRITERION

2.1 Statement of Resource Adequacy Criterion

For planning purposes, New Brunswick, Nova Scotia, PEI and Northern Maine individually apply a capacity-based reserve criterion in determining their required reserves.

New Brunswick and Northern Maine each plan for a reserve equal to the greater of the capacity of the largest generator or 20% of the firm load. Nova Scotia plans for a reserve equal to 20% of its firm load and PEI plans for a reserve equal to 15% of its firm load. As a simplification, this review applies the 20% reserve criterion to the Maritimes Area as a whole because of the relatively small size of PEI compared to the rest of the Maritimes Area. Thermal and hydro generators are considered available at the Dependable Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC resource adequacy criterion (from *NPCC Directory #1 Design and Operation of the Bulk Power System, Requirement 4 (Dated: September 9, 2020*) states:

> "**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.
>
> **R4.1** Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

2.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area, each separate jurisdiction remains under the exclusive control of its system operator for economic dispatch. For reliability purposes, however, reserve sharing agreements do exist and the separate systems operate within a common Reliability Coordinator area in accordance with NERC and NPCC criteria and guidelines.

Actions taken by the Energy Coordinator/Dispatcher, when faced with a developing or sudden capacity shortage, are based upon a number of possible actions best suited to the prevailing system conditions. In practice, the corrective actions taken are one or more of the following Emergency Operation Procedures (EOP):

1. Synchronize and load all available hydro generators.

2. Bring on-line generators up to their DMNC.

3. Cancel economy and other external interruptible sales.

4. Begin start-up procedures for “cold-standby” thermal generators.

5. Synchronize and load combustion turbines.

6. Purchase capacity from Hydro-Québec.

7. Purchase capacity from New England.

8. Cut interruptible sales to industrial customers (See Table A-1).

9. Maximize MVAR support (capacitor banks, synchronous condensers) if capacity shortage is causing a low voltage condition in a particular area.

10. Implement a 5% voltage reduction at selected substations within Nova Scotia (1–5 MW)

11. Appeal to the public for voluntary customer load reduction.

12. Disconnect customer loads as necessary to correct either a local or widespread problem.

Some or all of the above steps may be used in varying sequence to meet a capacity shortage depending on the generation pattern in effect at the time and whether or not the shortage results in localized internal system problems.

Although steps 10 and 11 are valid, the level of assistance available from these procedures is not modeled in this study.

2.3 Maritimes Area Reserve Criterion

The Maritimes Area employs a reserve criterion of 20% of firm load. The required installed reserve is shown in Section 3.1.

2.4 Relationship of Maritimes Reserve Criterion to NPCC Reliability Criterion

To relate the Maritimes Area reserve criterion of 20% to the NPCC resource adequacy criterion as stated in Section 2.1, LOLE was evaluated with the Maritimes Area firm load scaled up so that the reserve was equal to 20%. The results showed that a Maritimes Area reserve of 20% corresponds to a LOLE of approximately 0.081 days per year. At this load level, only about 40 MW of additional load was required to match the NPCC LOLE resource adequacy criterion of 0.1 days per year.

The preceding demonstrates that the 20% Maritimes Area reserve criterion correlates closely with the 0.1 days/year NPCC LOLE resource adequacy criterion for this review period.

2.5 Recent Reliability Studies

Resource Planners in New Brunswick, Nova Scotia, PEI, and Northern Maine individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criterion described previously.

The results presented in this review are based upon an evaluation conducted in 2022 for the period 2023 through 2027. This review supplants the previous Comprehensive Review that was performed in 2019 and approved by the RCC on December 3, 2019. Interim Reviews of resource adequacy for the Maritimes Area were completed in the years 2020 and 2021 covering the years 2021–2024 and 2022–2024 respectively. The results of this 2022 Comprehensive Review are consistent with these two previous Interim Reviews showing the Maritimes Area complying with the NPCC resource adequacy criterion for all years.

2.6 Load Forecast Uncertainty

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6%. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models.

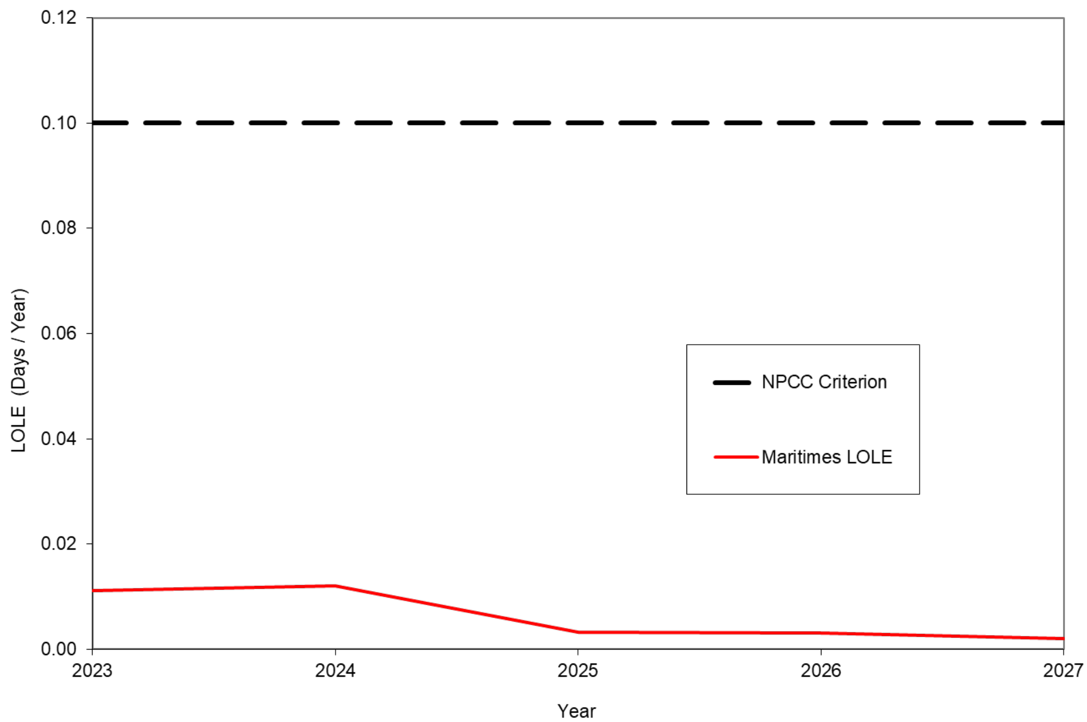
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, and 0.067 for the three results obtained using the base, 4.6 percent increased, and 9.2 percent increased load models respectively.

The LOLE analysis of the base case, including the impacts of LFU, as shown in Table 4 and Figure 2 demonstrates that the Maritimes Area system meets the NPCC resource adequacy criterion of no more than 0.1 days/year from 2023 to 2027.

Table 4: LOLE days/year – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number of Firm Load Disconnections days/year
2023	0.011
2024	0.012
2025	0.003
2026	0.003
2027	0.002

Figure 2: LOLE (days/year) – Base Case with Load Forecast Uncertainty



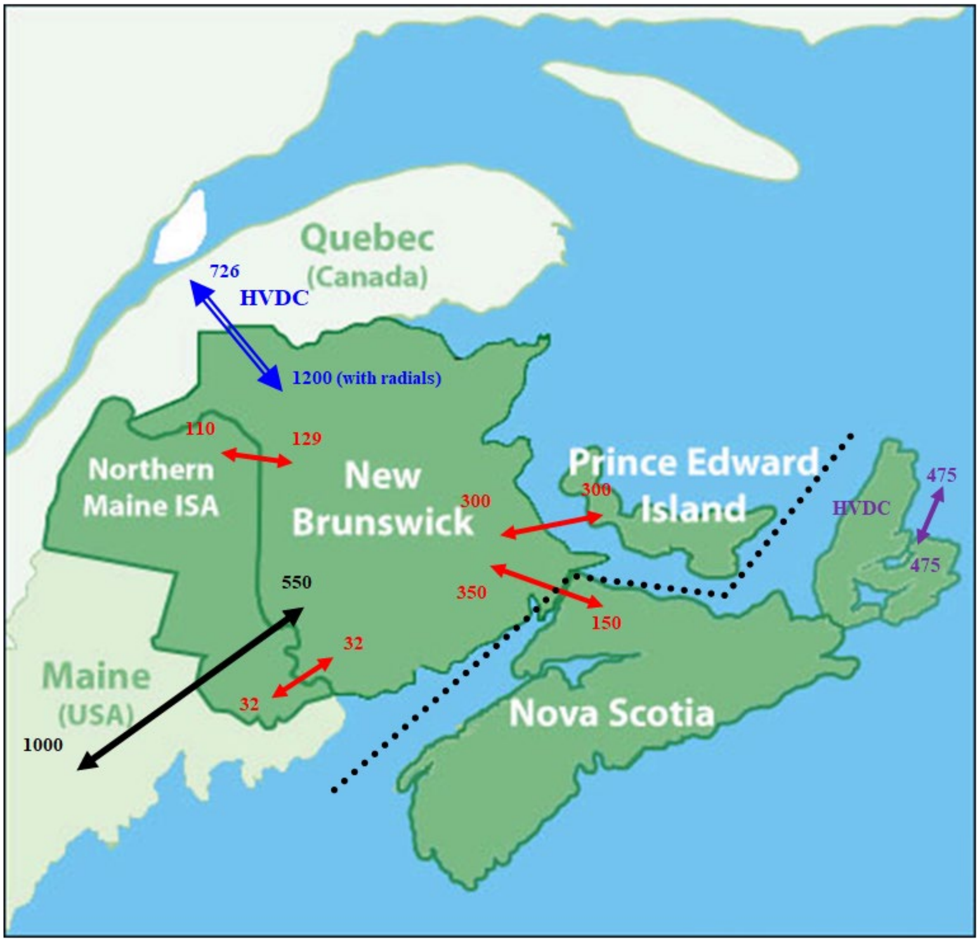
2.7 Intra-Area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected only to New Brunswick as per Figure 3. A transmission congestion issue of consequence to the LOLE occurs for only one of these three interconnections, the tie between New Brunswick and Nova Scotia.

Transmission capacity limits between Northern Maine and New Brunswick were not modeled for this analysis. These normal limits are a result of parallel operation of four lines (two 138 kV, two 69 kV) that Northern Maine keeps below thermal ratings to ensure that the trip of one of these lines doesn't overload the others. Should one or more contingencies occur in Northern Maine, the lines can be switched from parallel to radial operating modes. This effectively allows a high enough transfer limit from New Brunswick to meet the peak load in Northern Maine.

Late in 2017, PEI installed two additional undersea cables between New Brunswick and PEI. Based on a tripling of cable capacity and two additional parallel paths, the single cable contingency limiting flows from NB to PEI was eliminated. For this review, the transmission limit for this path was increased from 222 MW to 300 MW.

Figure 3: Maritimes Area Transmission Capacity Limits



3.0 RESOURCE ADEQUACY ASSESSMENT

3.1 Comparison of Forecast and Required Reserve – Base Case

In the comparison of the forecast and required reserve, the following definitions apply. The required reserve of 20% is the reserve criterion used for the Maritimes Area. The forecast reserve is the actual reserve that will occur during the peak load hour for each year.

Table 5 represents the results of the reserve comparison using the hourly coincident peak load forecast for the Maritimes Area. The corresponding capacity values incorporate all known firm sales and purchases with external neighboring areas and modeling wind generation production using 2017 wind shapes from each Maritimes Area sub-area. In each year of the analysis, both the forecast and minimum reserves are greater than the required reserve.

Table 5: Forecast, Minimum, and Required Reserve Levels – Base Case

Month of January	Forecast* Capacity	Peak Load	Inter. Load	Forecast Reserve		Minimum Hourly Reserve		Required Reserve	
	MW	MW	MW	MW	%	MW	%	MW	%
2023	6,973	5,583	294	1,684	32	1,643	32	1,058	20
2024	7,064	5,617	302	1,748	33	1,682	32	1,063	20
2025	7,195	5,643	320	1,872	35	1,750	34	1,065	20
2026	7,207	5,669	333	1,871	35	1,747	34	1,067	20
2027	7,293	5,693	337	1,937	36	1,805	35	1,071	20

* Forecast capacity incorporates all known firm purchases/sales with neighbouring Areas and includes forecast wind generation production coincident with the peak load.

$$\text{Forecast Reserve (\%)} = \frac{[\text{Forecast Capacity} - (\text{Peak Load} - \text{Inter. Load})]*100\%}{(\text{Peak Load} - \text{Inter. Load})}$$

$$\text{Minimum Reserve (\%)} = \frac{\text{Min. of Hourly }[\text{Capacity} - (\text{Load} - \text{Inter. Load})]*100\%}{(\text{Load} - \text{Inter. Load})}$$

3.2 LOLE results – High Load Growth

Table 6 and Figure 4 illustrate LOLE results if the average annual growth rate is 1% higher than forecast (i.e., +1.49% per year versus 0.49% per year compounded over the last four-year period of this review). The results show that the NPCC resource adequacy criterion is met in all years.

Table 6: Loads and LOLE Results – High Load Growth

Month of January	High Load Growth Load	Base Case Load	Difference	High Load Growth LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2023	5,583	5,583	0	0.011	0.011
2024	5,666	5,617	49	0.016	0.012
2025	5,750	5,643	107	0.006	0.003
2026	5,836	5,669	167	0.009	0.003
2027	5,923	5,693	230	0.009	0.002

3.3 LOLE Results – 50% Wind Derate

The Maritimes Area models forecast wind generation production on an hourly basis for its LOLE and reserve calculations. Year 2017 hourly wind shape was used to simulate the wind projections. The on-peak wind generation values do not represent the effective load carrying capability or capacity value of the wind resources due to the variability of wind from hour-to-hour in the wind shape used. The installed wind capacity in the Maritimes rose from 1,264 MW in 2023 to 1,914 MW in 2027. Simulated wind capacity during the Maritimes coincident peak demand rose from 306 MW in 2023 to 508 MW by 2027. Kent Hills 1 and 2 wind sites of total nameplate capacity of 150 MW were assumed to be offline during the first half of the year 2023 in the base and all sensitivity cases of this review. A sensitivity analysis was performed in which the total available installed wind capacity on the system is derated by 50% for all hours in this review. Table 7 and Figure 4 illustrate LOLE results for the above scenario.

Table 7: Capacity and LOLE Results – 50% Wind Derate

Month of January	50% Wind Derate Capacity	Base Case Capacity	Difference	50% Wind Derate Capacity LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2023	6,819	6,973	-153	0.022	0.011
2024	6,875	7,064	-188	0.027	0.012
2025	6,960	7,195	-235	0.008	0.003
2026	6,964	7,207	-242	0.008	0.003
2027	7,039	7,293	-254	0.006	0.002

3.4 LOLE Results – No Tie Benefits

Since 2011, NB Power has assumed 300 MW of tie benefits in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighboring jurisdictions have not been considered since they also experience peak loads in winter.

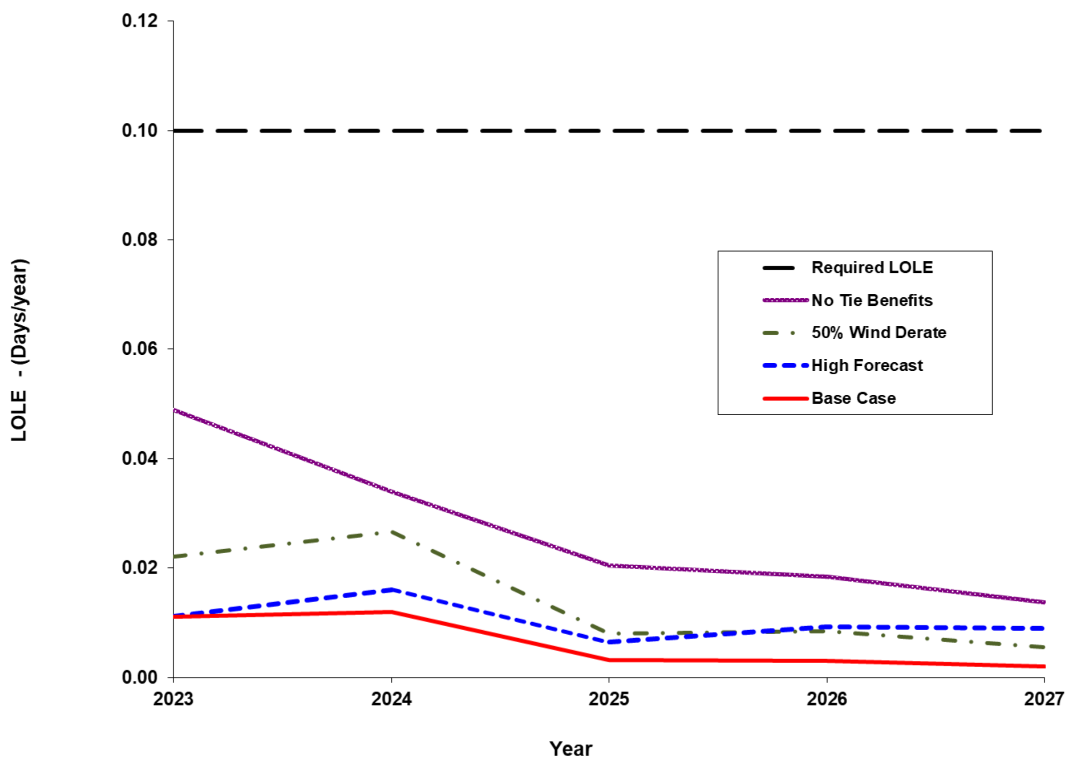
In the CP-8 report *Review of Interconnection Assistance Reliability Benefits*[*] *(December 31, 2021, Approved by RCC March 2, 2022)* the "As Is" scenario estimated tie benefit potential for the Maritimes Area to be 1,574 MW and 1,506 MW for the years 2022 and 2026 with an export of 66 MW modeled in year 2022. Based on this study, the 300 MW of tie benefits assumed for this 2022 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does not require interconnection assistance to meet the NPCC resource adequacy criterion. The results are shown in Table 8 and Figure 4.

Table 8: Capacity and LOLE Results – No Tie Benefits

Month of January	No Tie Benefits Capacity	Base Case Capacity	Difference	No Tie Benefits LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2023	6,673	6,973	-300	0.049	0.011
2024	6,764	7,064	-300	0.034	0.012
2025	6,895	7,195	-300	0.021	0.003
2026	6,907	7,207	-300	0.018	0.003
2027	6,993	7,293	-300	0.014	0.002

[*] 2021 Review of Interconnection Assistance Reliability Benefits

Figure 4: LOLE Results – Base and All Sensitivity Cases



3.5 Contingency Plans

The Maritimes Area utilities' forecast high and low load growth scenarios, and their impact on the generation dispatch is continually being evaluated to address load and resource uncertainties. In the event of a higher than expected growth in load, a number of options would be considered. These options include the purchases of capacity and/or energy, the advancement of base load generation additions, and the installation of combustion turbines.

4.0 FORECAST RESOURCE CAPACITY MIX

Installed wind of 1,264 MW in the Maritimes Area is expected at the start of 2023. Kent Hills 1 and 2 wind sites in New Brunswick of total nameplate capacity of 150 MW were assumed unavailable during the first half of the year 2023. The available wind capacity without Kent Hills 1 and 2 wind sites is 1,114 MW during the first half of 2023. Wind generation of 100 MW, 410 MW, 40 MW and 100 MW were added in years 2024, 2025, 2026 and 2027 respectively. A new energy storage resource of 200 MW nameplate capacity was added in Nova Scotia starting in December 2024. The firm capacity contribution of this addition is 104 MW (assumes an ELCC of 52%). Hydro imports include 153 MW firm capacity starting June 2022 and an additional import of 85 MW starting December 2023 from the province of Newfoundland and Labrador. Thermal capacity addition in the area include 18 MW diesel fueled generator in 2023, conversion of a 150 MW coal unit to natural gas in late 2024, 150 MW and 50 MW natural gas combustion turbines† in late 2025 and 2026 respectively and 50 MW diesel fired generation in 2026.

Retirements include a 4 MW hydro unit in July 2022, coal unit of 148 MW in Mar. 2023, diesel units totaling 3 MW in Oct. 2023, coal unit of 150 MW in Nov. 2024 and natural gas/HFO dual fuel units totaling 171 MW in Dec. 2025. Resource additions must first demonstrate reliable performance before corresponding retirements are fully decommissioned.

4.1 Forecast Resource Capacity Mix

Table 9 and Figure 5 illustrate the forecast resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

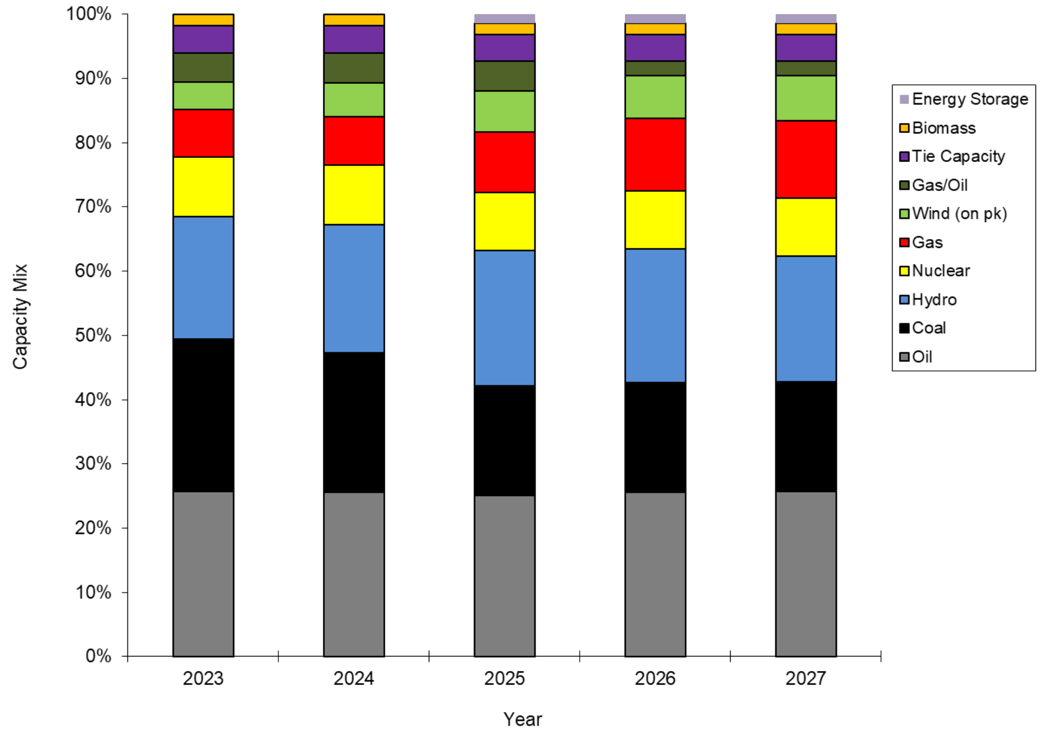
Table 9: Forecast Capacity Resource Mix

Month of January	Oil	Coal	Hydro	Nuclear	Gas	Wind*	Gas/Oil	Tie Benefits	Biomass	Energy storage**
	%	%	%	%	%	%	%	%	%	%
2023	26	24	19	9	7	4	4	4	2	0
2024	26	22	20	9	7	5	5	4	2	0
2025	25	17	21	9	9	6	5	4	2	1
2026	26	17	21	9	11	7	2	4	2	1
2027	26	17	20	9	12	7	2	4	2	1

* Wind capacity based on forecast wind production during Maritimes coincident peak
** Energy storage resource of 200 MW nameplate capacity was added in Nova Scotia starting in December 2024. The firm capacity contribution of this addition is 104 MW (assumes an ELCC of 52%).

† While these additions are currently modeled as gas units, on-going studies will include consideration for dual fuel and low/zero carbon alternative fuels to mitigate the risk associated with limited gas supplies.

Figure 5: Forecast Capacity Resource mix



4.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 9 and the associated Figure 5, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. In NB, the current Renewable Portfolio Standard (RPS) target requires 40% of annual energy sales to be supplied from renewable resources. Current year-to-date target show 42% of annual energy sales come from renewable sources, which include primarily wind generation and hydro. The Renewable Electricity Standard (RES) in Nova Scotia calls for 40% of annual energy sales to be supplied from renewable resources. RES energy is provided primarily by wind generation, hydro, biomass, and the energy import from the Muskrat Falls Hydro Generating Project in the Canadian province of Newfoundland and Labrador. The RES in Nova Scotia will increase to 80% in 2030. Part of the increase will be met by future energy storage and wind additions included in this review; planning is underway to determine the remaining 2030 renewable requirement.

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 Calendar year 2017 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2023 to 2027 inclusive were prepared by each resource planner. The combined load and energy forecasts for the Maritimes Area are shown in Table A-1.

Table A-1: Maritimes Area Load Forecast

COINCIDENT DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Peak**
2023	5,583	5,469	4,930	4,133	3,482	3,201	3,245	3,293	3,250	3,553	4,424	5,132	5,583
2024	5,617	5,491	4,948	4,152	3,489	3,225	3,269	3,315	3,273	3,574	4,440	5,167	5,617
2025	5,643	5,517	4,970	4,169	3,494	3,241	3,279	3,342	3,293	3,596	4,454	5,200	5,643
2026	5,669	5,549	4,989	4,198	3,500	3,260	3,298	3,360	3,314	3,611	4,474	5,233	5,669
2027	5,693	5,568	5,007	4,216	3,515	3,282	3,318	3,379	3,333	3,629	4,487	5,269	5,693
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2023	3,108	2,794	2,742	2,273	2,062	1,858	1,973	1,991	1,878	2,101	2,377	2,860	28,018
2024	3,114	2,802	2,746	2,281	2,072	1,862	1,979	1,997	1,885	2,108	2,384	2,868	28,097
2025	3,115	2,800	2,749	2,275	2,065	1,862	1,978	1,997	1,885	2,108	2,384	2,866	28,084
2026	3,116	2,802	2,749	2,281	2,073	1,863	1,979	1,996	1,885	2,107	2,383	2,865	28,097
2027	3,114	2,801	2,748	2,279	2,067	1,864	1,979	1,998	1,886	2,109	2,386	2,868	28,098
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2023	294	296	356	346	339	378	369	376	375	368	364	300	294
2024	302	305	357	349	343	384	375	383	382	374	370	315	302
2025	320	322	362	352	344	386	376	384	383	375	371	329	320
2026	333	335	364	353	345	387	377	384	383	375	371	340	333
2027	337	339	363	353	345	387	377	384	383	375	371	343	337

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.6 of the main report.

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. Only the portions that are supplied by the Maritimes Area utilities were included in the area forecast.

1.4 The load forecast in Table A-1 includes the impact of DSM and efficiency programs.

2.0 Generator Resource Representation

Generator data for the four members of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2023–2027 inclusive. The following sections document the tabulated data.

2.1 Generator Ratings

2.1.1 Definition

The generator capacity ratings represented in Table A-2 are the Dependable Maximum Net Capability (DMNC) winter ratings. These are evaluated periodically to establish each generator's sustained maximum net output over a two consecutive hour period.

2.1.2 Procedure for Verifying Ratings

With the July 1, 2019 retirements of NPCC directories #9 and #10, testing and verification of transmission and generator facility ratings are governed by NERC reliability standard MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability (Attachment 1). This standard establishes the methodologies and performance requirements necessary to ensure generating facilities are tested at least every 5 years to verify they can meet their ratings under operating conditions. A link to this standard is provided here:

NERC Standard MOD-025-2

Table A-2: Maritimes Area Resources

New Brunswick Resources as of January 1, 2023				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Point Lepreau	1	Nuclear	660	
Belledune	2	Coal	466	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Bayside	6	Natural Gas	290	Capacity (Combined Cycle Operation)
Grand Manan	3	Diesel	28	
Millbank	1	Diesel	99	Summer Capacity = 86MW
	2	Diesel	99	Summer Capacity = 86MW
	3	Diesel	99	Summer Capacity = 86MW
	4	Diesel	99	Summer Capacity = 86MW
Ste Rose	1	Diesel	99	Summer Capacity = 86MW
Grandview	1	Natural Gas	49	
	2	Natural Gas	49	
NUG Purchases		Biomass	38	
		Hydro	15	
Small Producers		mostly Hydro (NUG)	10	
Mactaquac	1	Hydro	109	
	2	Hydro	109	
	3	Hydro	109	
	4	Hydro	115	
	5	Hydro	112	
	6	Hydro	112	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Nepisiguit Falls	1	Hydro	11	
Sisson	1	Hydro	9	
Milltown	1	Hydro	0	Assumed retired eff. July 2022
Tie Benefits			300	
NB Wind	All	Wind	69	During Maritime peak (369 MW installed, derated to 219 MW)
TOTAL CAPACITY			4,324	Total Capacity as of January 2023

Table A-2: Maritimes Area Resources (cont'd)

Nova Scotia Resources as of January 1, 2023				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Lingan	1	Coal	153	Summer Capacity = 146 MW
	2	Coal	148	Summer Capacity = 141MW
	3	Coal	153	Summer Capacity = 146 MW
	4	Coal	153	Summer Capacity = 146 MW
Trenton	5	Coal	150	Summer Capacity = 0 MW (Due to operating restrictions)
	6	Coal	154	Summer Capacity = 115 MW
Pt. Tupper	2	Coal	150	Summer Capacity = 145 MW
Tufts Cove	1	Gas/Oil	78	Summer Capacity = 74 MW
	2	Gas/Oil	93	Summer Capacity = 91 MW
	3	Gas/Oil	147	Summer Capacity = 144 MW
	4	Natural Gas	49	Summer Capacity = 45 MW
	5	Natural Gas	49	Summer capacity = 45 MW
	6	Natural Gas	46	Summer Capacity = 41 MW
Pt. Aconi	1	Coal	168	Summer Capacity = 166 MW
Burnside	1	Lt Oil	33	Summer Capacity = 25 MW
	2	Lt Oil	33	Summer Capacity = 25 MW
	3	Lt Oil	33	Summer Capacity = 25 MW
	4	Lt Oil	33	Summer Capacity = 25 MW
Victoria Junction	1	Lt. Oil	33	Summer Capacity = 25 MW
	2	Lt. Oil	33	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	33	Summer Capacity = 25 MW
NSIPP1 NUG Purchases	All	Biomass	26	2 MW Mothballed
PH Biomass		Biomass	43	
COMFIT Biomass	All	Biomass	3	
				All Hydro units assume an ELCC of 95%
Wreck Cove	1	Hydro	0	Planned maintenance until July 2024
	2	Hydro	101	
Annapolis Tidal		Hydro	0	
Avon 1&2		Hydro	6	
Black River		Hydro	21	
Nictuax		Hydro	8	
Lequille		Hydro	11	
Paradise		Hydro	5	
Mersey		Hydro	40	
Sissiboo		Hydro	26	

Bear River		Hydro	10	
Tusket		Hydro	2	
St. Margrets		Hydro	10	
Sheet Harbour		Hydro	10	
Dickie Brook		Hydro	4	
Fall River		Hydro	0	
NALCOR Firm Contract		Hydro	153	
NS Wind Projects	All	Wind	141	During Maritime peak (618.5 MW installed)
TOTAL CAPACITY			2,543	Total Capacity as of January 2023

Table A-2 Maritimes Area Resources (cont'd)

Prince Edward Island Resources as of January 1, 2023				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Charlottetown	CT3	Diesel	49	Summer Capacity = 40 MW
Borden	1	Diesel	14	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside Diesels	1	Diesel	2	Owned by the City of Summerside
	2	Diesel	2	Owned by the City of Summerside
	3	Diesel	2	Owned by the City of Summerside
	5	Diesel	2	Owned by the City of Summerside
	6	Diesel	1	Owned by the City of Summerside
	7	Diesel	1	Owned by the City of Summerside
	8	Diesel	4	Owned by the City of Summerside
PEI Wind	All	Wind	86	During Maritime peak (234 MW installed)
TOTAL CAPACITY			188	Total Capacity as of January 2023

Table A-2 Maritimes Area Resources (cont'd)

Northern Maine Resources as of January 1, 2023				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Tinker		Hydro	35	
Caribou		Hydro	0	1 MW mothballed January 1 2023
Squa Pan		Hydro	1	
EMEC		Oil/Hydro	20	
NMISA Wind	All	Wind	11	During Maritime peak (42 MW installed)
TOTAL CAPACITY			67	Total Capacity as of January 2023

Table A-3: Summary of Changes in Modeled Capacity

Month/ Year	Capacity Change MW	Capacity Balance MW	Explanation Total Capacity includes installed capacity, tie benefits, firm purchases and/or sales, and planned maintenance
Jan. 1, 2023	0	6,973	Starting Capacity
	+149/-72	7,050	Removal of 149 MW sale after May, Addition of 72 MW sale starting June in NB
	-148	6,902	Removal of 148 MW Coal unit end of Mar. 2023 in NS
	- 6.8	6,895	Derate of a Hydro unit for a planned maintenance starting July 2023 in NS
	+ 70	6,965	Additional 70 MW of simulated Wind on coincident peak
	+ 18	6,983	Addition of 18 MW of Diesel unit starting Oct. 2023 in PEI
	- 3	6,979	Removal of a total of 3 MW Diesel unit starting Oct. 2023 in PEI
	+ 85	7,064	Addition of 85 MW firm hydro import starting Dec. 2023 in NS
Jan 1, 2024	+72/-90	7,046	Removal of 72 MW sale after May, Addition of 90 MW sale starting June in NB
	- 150	6,896	Removal of 150 MW of Coal unit starting Nov. 2024 in NS
	+ 150	7,046	Conversion of 150 MW of above Coal unit to Natural Gas starting Nov. 2024 in NS
	- 150	6,896	Removal of 150 MW of Coal unit starting Dec. 2024 in NS
	+ 100.7	6,997	Return of 100.7 MW of Hydro unit after planned maintenance starting July 2024 in NS
	+ 94	7,091	Additional 94 MW of simulated Wind on coincident peak
	+104	7,195	Addition of an Energy storage resource of 104 MW (52% ELCC of 200 MW nameplate capacity) starting Dec. 2024 in NS

Jan 1, 2025	+90/-122	7,163	Removal of 90 MW sale after May, Addition of 122 MW sale starting June in NB
	- 171	6,992	Retirement of 171 MW of Dual fuel units starting Dec. 2025 in NS
	+ 150	7,142	Addition of 150 MW of Gas turbine units starting Dec. 2025 in NS
	+ 14	7,156	Additional 14 MW of simulated Wind on coincident peak
Jan 1, 2026	+50	7,206	50 MW of Diesel unit added in Jan. 2026 in PEI
	+ 122	7,328	Removal of 122 MW sale after May in NB
	+ 50	7,378	Addition of 50 MW of Gas turbine unit starting Dec. 2026 in NS
Jan 1, 2027	-109	7,269	Reduction of 109 MW of Hydro unit for planned refurbishment starting Jan. 2027 in NB
	+ 23	7,293	Additional 23 MW of simulated Wind on coincident peak

2.2 Generator Unavailability Factors

2.2.1 Types of Unavailability Factors Represented

The types of unavailability factors represented in this reliability assessment are forced outages and planned outages. Forced outages include unplanned maintenance outages, deferrable forced outages, starting failure outages and generator derating adjustments. All except planned outages are included in the Forced Outage Rates (FORs) presented in Table A-4. Planned outages are scheduled manually for the reliability program based upon projected maintenance schedules.

New Brunswick forced outage rates are five-year calculations using the Derating Adjusted Forced Outage Rate (DAFOR) methodology in IEEE Standard 762-2006, Section 8.17.4.

NSPI uses three-year average DAFOR calculations for forced outage rates consistent with IEEE Standard 762-2006, Section

8.17.4. NSPI maintains a database of combustion turbine and fossil generator reliability and performance data and is a contributing utility to the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS). The CEA-ERIS also calculates DAFOR using the industry standard definition as per IEEE 762-2006. The forced outage rates for the smaller PEI and Northern Maine systems are modeled using forced outage rates for generators of similar size and fuel type in New Brunswick and Nova Scotia. Most of the small diesel and oil fueled generators in these systems operate less than 100 hours per year, and statistics necessary for calculating their DAFOR values are not available. The modeled FOR values for generators in these systems are between 5 – 10 %.

2.2.2 Source of Unavailability Factors

Forced Outage Rates for existing generators are based on actual outage data as well as on data of similar sized generators as compiled by the Canadian Electricity Association (CEA).

FORs for new generators are based upon the utilities' experience with similar generators in conjunction with averages compiled by the Canadian Electricity Association (CEA).

2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

2.2.4 Tabulation of Forced Outage Rates

The ranges of FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the Maritimes Area utilities and reflect the results of maintenance and operational strategies.

Table A-4: Maritimes Area Forced Outage Rates

Unit Type	DAFOR Forced Outage Rates (weighted)	
	2022 Review*	2019 Review*
Oil	5%	4%
Coal	5%	3%
Hydro	3%	3%
Nuclear	5%	4%
Natural Gas	4%	3%
Wind	0%	0%
Oil/Gas	6%	16%
Biomass	4%	2%
Energy storage**	2%	NA

* 2019 review based on 3-year average DAFOR calculations for FORs in NB and NS, 2022 review based on 5-year average DAFOR calculations for FORs in NB and 3-year average DAFOR calculations for FORs in NS

** 2% FOR was assumed for the Energy storage as historical data is currently unavailable for this resource type

2.3 Purchase and Sale Representation

External purchases and sales are represented as positive or negative adjustments to the Maritimes Area capacity respectively.

2.4 Retirements

Retirements were considered by removing the generators from the model at their retirement date.

Retirements include a 4 MW Hydro unit in NB starting July 2022, a coal unit in NS in March 2023, Diesel units totaling 3 MW in PEI starting Oct. 2023, Coal unit of 150 MW starting Nov. 2024 and Natural gas/HFO dual fueled units totaling 171 MW starting Dec. 2025 in NS. Thermal additions in combination with Hydro imports, wind and energy storage are planned to offset the impacts associated with the above retirements. Resource additions must first demonstrate reliable performance before corresponding retirements are fully decommissioned.

3.0 Representation of Interconnected Systems

Since 2011, NB Power has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighboring jurisdictions that are also winter peaking are not considered.

In the CP-8 report *Review of Interconnection Assistance Reliability Benefits*[‡] *(December 31, 2021, Approved by RCC March 2, 2022)* the "As Is" scenario estimated tie benefit potential for the Maritimes Area to be 1,574 MW and 1,506 MW for the years 2022 and 2026 with an export of 66 MW modeled in year 2022. Based on this study, the 300 MW of tie benefits assumed for this 2022 Comprehensive Review is conservative.

4.0 Modeling of Variable and Limited Energy Sources

Wind resources are modeled as simulated hourly values that are netted out against the hourly loads. The hourly wind shape for any Maritimes Area jurisdiction is based upon each jurisdiction's hourly wind production during the 2017 calendar year expressed as a percentage of the jurisdiction's total installed wind for the hour. Any new wind capacity forecast for a jurisdiction is modeled this same historical hourly wind shape. Since the area peak occurs in winter before and after sunset, peak capacity contribution from solar resources was considered as zero.

Under normal operating conditions, the hydro system is operated considerably below its DMNC rating due to economics. However, if required to maintain customer load, it would be operating at full capacity by utilizing the head ponds and other existing storage reservoirs. This is one of the options documented in the Emergency Operating Procedures (Section 2.2 of the main report). Therefore, in the evaluation, hydro generators are considered available for all hours during which the generator is not on forced outage or maintenance. There are no seasonal adjustments to the DMNC ratings of the hydro generators.

5.0 Modeling of Demand Side Management

The expected monthly demand and energy reduction due to Demand Side Management programs for each sub-area is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

[‡] 2021 Review of Interconnection Assistance Reliability Benefits

6.0 Modeling of Non-Utility Generation

Certain small non-utility generators are aggregated into single units with operating characteristics and FORs equivalent to other Maritimes Area generators of similar size. These are tabulated in Table A-2 and are identified by type NUG.

7.0 Other Assumptions

The study assumed that there would be no generator slippages or deratings due to environmental constraints within the five-year timeframe of this review.

In NB, current emission limits are specified as annual system volumes without constraining any specific generation capacity limits.

In NS, current regulations limiting air pollutants are in place for the 2022-2030 timeframe which specify multi-year hard caps rather than annual limits providing for some flexibility in the operation of the fleet over the specified compliance periods. Greenhouse gas emissions are based on the Federal Backstop carbon pricing mechanism as prescribed by the Output-Based Pricing System (OBPS). NS Power understands the province will continue to work with Environment and Climate Change Canada to establish the Carbon Policy framework for Nova Scotia from 2023 through to 2030. System Operators in the Maritimes Area will be tracking such regulations and standards as they are implemented and may conduct analyses in the future regarding their impact on resource adequacy.

APPENDIX B - DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

The program used for this assessment, LOLP, was originally developed at NB Power in 1984 to complete the Triennial Review of Resource Adequacy. Since that time the program has been improved, and its capabilities expanded, with the most recent modifications being completed during the winter of 2018/19.

The original program was a single area program that performed the classical Loss of Load Probability (LOLP) analysis based upon the weekday peak hour load, as well as a Loss of Load Hours (LOLH) and Expected Energy Not Served (EENS) analysis which is based upon all of the hourly loads. The results of the program were benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NSPI for the 1991 Triennial Review. The program was further benchmarked by evaluating its results against those documented in the 1992 CIGRE Task Force 38-03-10 report "Composite Power System Reliability Analysis Application to the New Brunswick Power Corporation System"". In all cases, excellent agreement of results was observed.

In the fall of 2007, modifications to the original program allowed it to perform a Monte Carlo analysis of a multi-area system with intra-area tie limits. This Monte Carlo simulation was written using MATLAB® software for programming and random number generation, and it performs as follows:

- For each daily coincident peak load, generation is simulated in each jurisdiction of the Maritimes. In the case of wind generation, hourly wind generation projections for the time of the Area coincident peak are netted against the loads. This simulation uses random numbers against a generator's Forced Outage Rate to determine the status of each generator. Planned generator maintenance is also enforced.
- Generation surpluses or deficits are determined for each intra-area jurisdiction. Because each jurisdiction other than New Brunswick (NB) is only connected to NB, these surpluses and deficits can be transferred to New Brunswick.
- Surpluses transferred to NB from another intra-area jurisdiction are limited by the export limit of the jurisdiction.
- Deficits in an intra-area jurisdiction other than NB that exceed the import capability from NB results in a loss of load event. Otherwise, the deficit is transferred to NB. If more than one sub-area experiences a loss of load contingency on the same day, it is included as a single loss of load event for the Maritimes area as a whole.
- With all transfer-limited intra-area surpluses and deficits transferred to NB, it is determined whether or not the simulated generation in NB plus transferred surpluses is adequate to supply both the NB load and any transferred deficits. If not, then a loss of load event occurs.
- The Monte Carlo simulation is performed for each daily peak hour of the year, and the yearly simulation is repeated 100,000 times to calculate the average LOLE in days/year.

The base load shape for the program is system hourly net loads for each jurisdiction comprising the Area. Monthly load shapes for the individual jurisdictions are created by scaling the hourly loads to match the load forecast values of both demand and energy. This method preserves the effects of load chronology as well as load coincidence between the jurisdictions. This method is also identical between the new program and the old program. A separate monthly load shape comprising only the peak load of each day is created for the LOLE analysis.