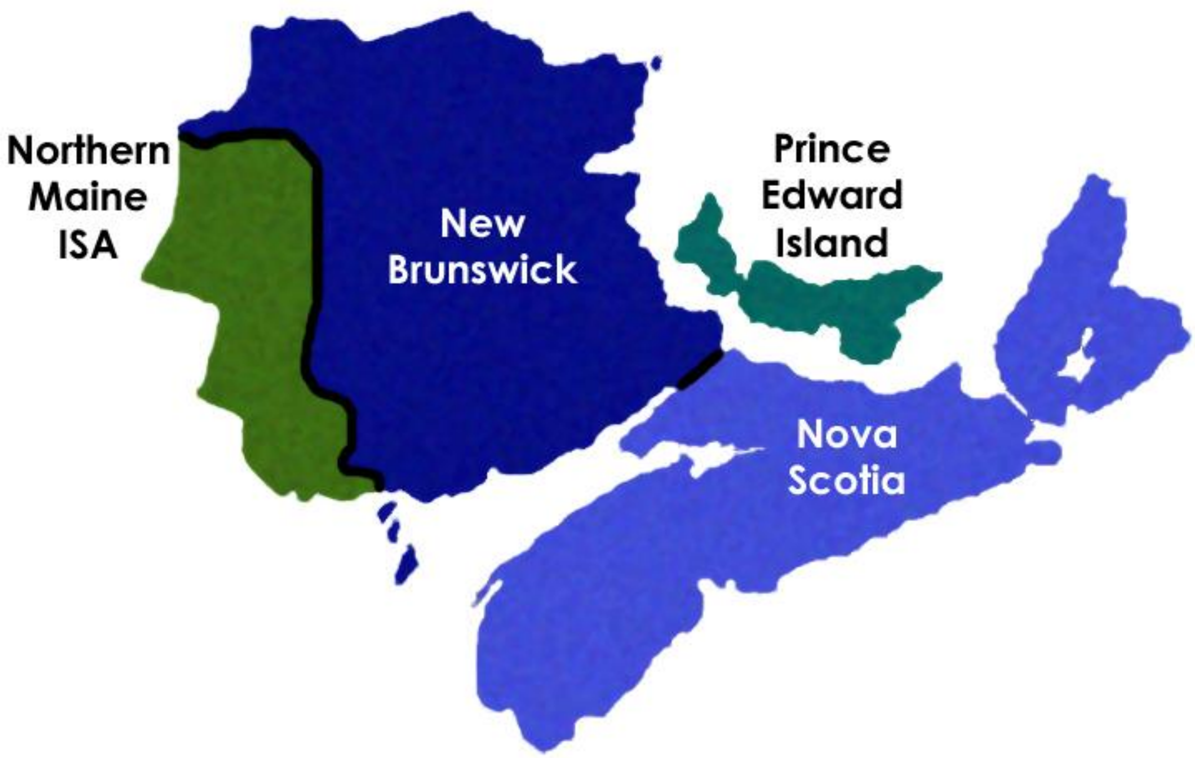
NPCC
2025 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY



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

Approved by the NPCC RCC on December 1, 2025

October 2025

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EXECUTIVE SUMMARY

The 2025 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2025 through December 2030, 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 (Revised: July 2, 2024)*. This review supplants the previous Comprehensive Review that was performed in 2022 and approved by the RCC on December 6, 2022.

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 exceeded by the Maritimes Area for the years, 2026 and 2027, but meets the adequacy criterion for the rest of the years covered by this review and varies between 0.001 to 0.269 days/year 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 follow the same pattern as the base case where the NPCC resource adequacy criterion not met in 2026, and 2027 but does meet the NPCC resource adequacy criterion for all remaining years for each of these sensitivities.

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

Table 1: Summary of Major Assumptions and Results

MAJOR ASSUMPTIONS	
Load Forecast	2024
Load and Wind Shape	2024
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: 2025/26 - 122 MW 2026/27 - 177 MW 2027/28 - 70 MW Firm Purchases: 153 MW from Newfoundland and Labrador

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
2026	0.245	0.245	0.391	1.024
2027	0.269	0.208	0.424	1.251
2028	0.020	0.029	0.023	0.045
2029	0.001	0.005	0.003	0.008
2030	0.001	0.002	0.003	0.004

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1.0 INTRODUCTION

The 2025 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2025 through December 2030, 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 (Revised: July 02, 2024)*. This review supplants the previous Comprehensive Review that was performed in 2022 and approved by the RCC on December 6, 2022.

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 2025 and 2024 reviews. The coincident peak demand forecast for 2026 is 6,178 MW, which is marginally higher than 6,129 MW forecast in the 2024 Interim Review. Demand shifting and energy efficiency programs are expected to reduce peak demand in the Maritimes Area by 266 MW to 352 MW during the 2025 Comprehensive Review period. The average annual demand growth over the period of this review is 0.09% as compared to 0.26% average demand growth forecast for 2026-27 in the 2024 review. A comparison of load forecasts is shown in Figure 1.

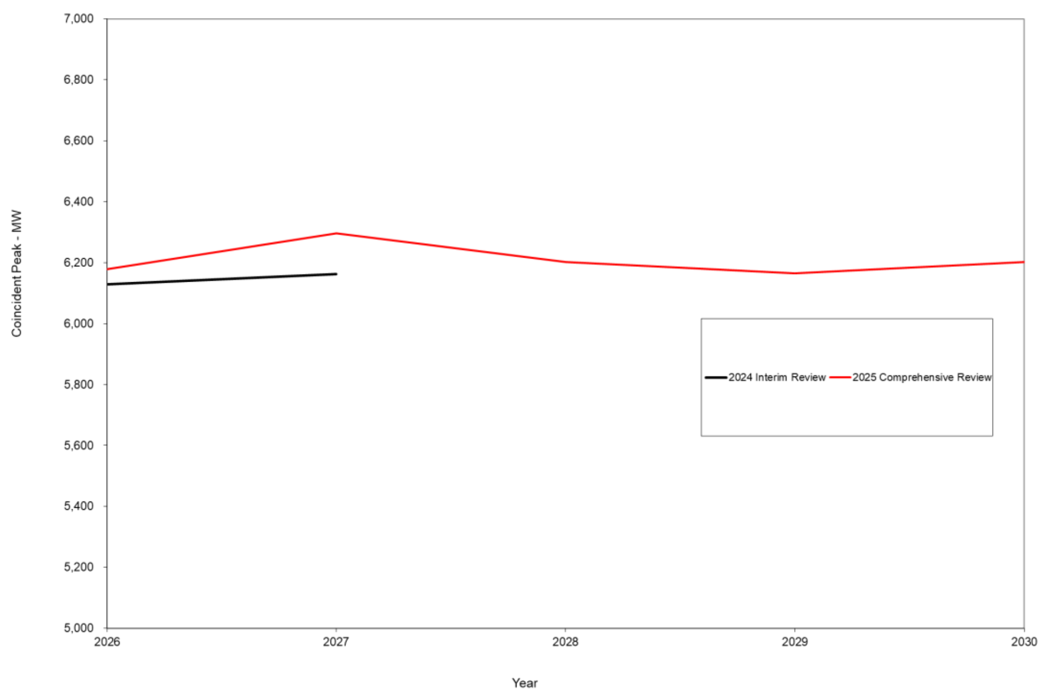
In addition to installed capacity, the resource forecast included in Table 3 incorporates external purchases and/or sales (as additions or reductions to the forecast respectively), tie benefits from neighboring utilities, and projections of on-peak wind production (reflecting both capacity changes as well as a 2024 and 2017 wind shape for both 2025 Comprehensive and 2024 Interim Reviews respectively).

Table 3: Comparison of Load and Resource Forecasts

Winter Peak (Month of January)	2025 Review Load MW	2024 Review Load MW	2025 Review Resources MW*	2024 Review Resources MW*
2026	6,178	6,129	7,366	7,428
2027	6,296	6,162	7,219	7,350
2028	6,202	N/A	7,625	N/A
2029	6,166	N/A	8,052	N/A
2030	6,202	N/A	9,474	N/A
Five Year Period	**2026–2030**	**2025–2027**		
Annual Average Growth Rate	0.09%	0.53%		

* 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 (Revised: July 2, 2024*) 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 several 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 economic 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 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 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 2025 for the period 2026 through 2030. This review supplants the previous Comprehensive Review that was performed in 2022 and approved by the RCC on December 3, 2022. Interim Reviews of resource adequacy for the Maritimes Area were completed in the years 2023 and 2024 covering the years 2024–2027 and 2025–2027 respectively. The results of this 2025 Comprehensive Review are consistent with these two previous Interim Reviews showing the Maritimes Area not complying with the NPCC resource adequacy criterion in the near term and meeting the criterion in the later years of the study. In order for the Maritimes area to be in compliance, approximately 300 MW of extra capacity would be required for meet the 0.1 days/year in 2026, while only 75 MW would be required in 2027.

2.5 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% based upon the four-year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models.

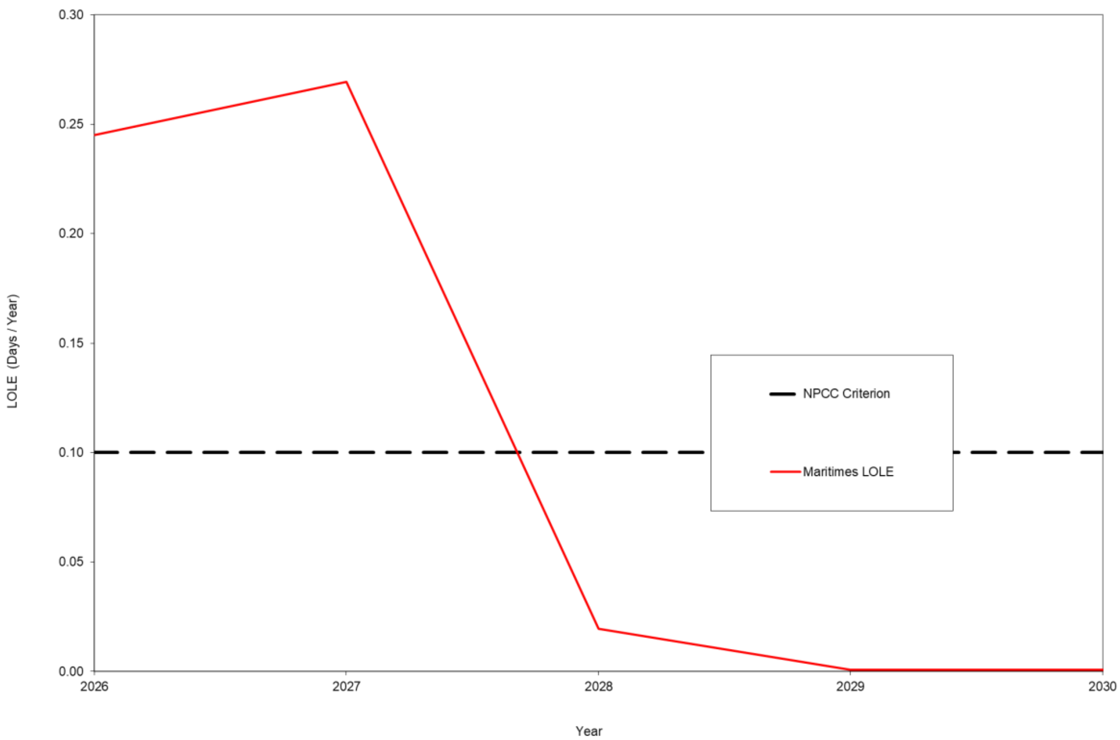
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, 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 does not meet the NPCC resource adequacy criterion of no more than 0.1 days/year in the years 2026, and 2027 but does meet the criterion for the remaining years of the study.

Table 4: Resource Adequacy Metrics – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number of Firm Load Disconnections days/year	Loss of Load Hours	Expected Unserved Energy (MWh)	Normalized Expected Unserved Energy
2026	0.245	0.580	64	0
2027	0.269	0.775	68	0
2028	0.020	0.046	1	0
2029	0.001	0.001	0	0
2030	0.001	0.001	0	0

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

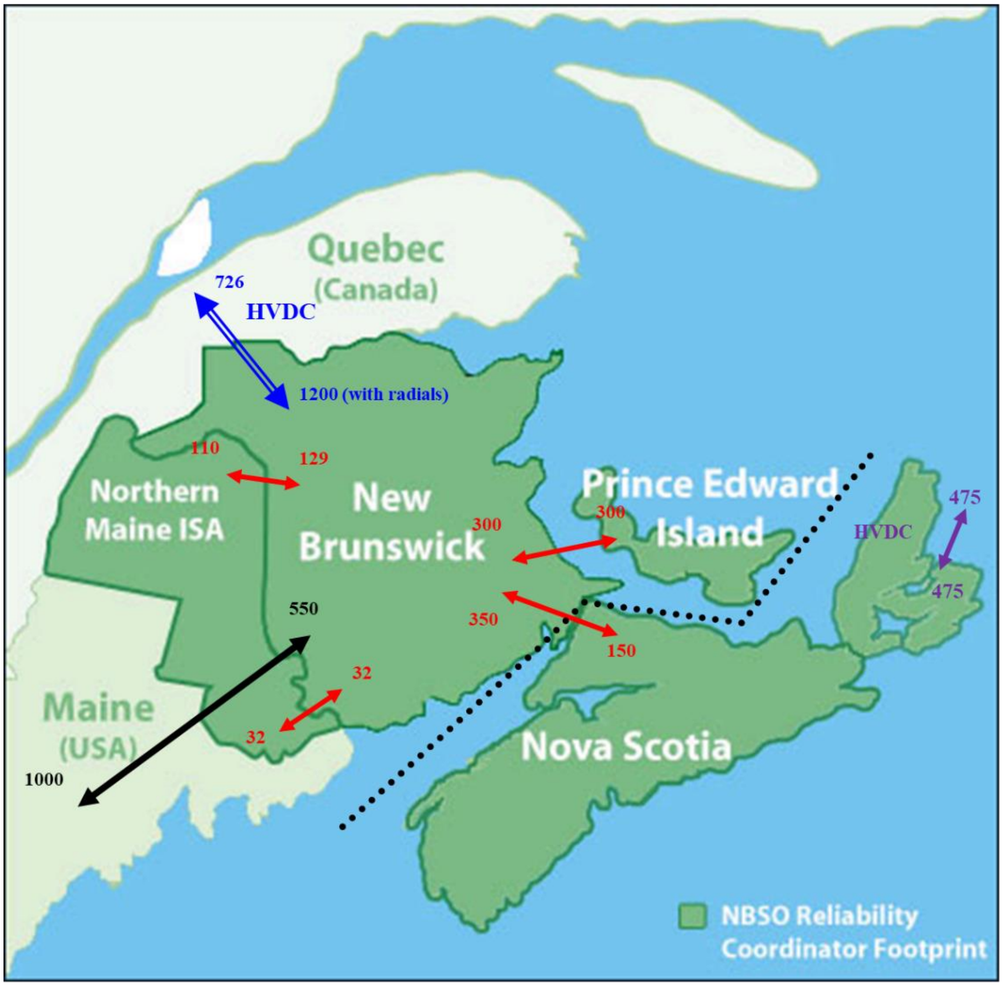


2.6 Intra-Area Transmission Capacity Limits

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.

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

2024 wind shapes from each Maritimes Area sub-area. In each year of the analysis, the forecast reserve 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	
	MW	MW	MW	MW	%
2026	7,366	6,178	273	1,461	25
2027	7,219	6,296	273	1,196	20
2028	7,625	6,202	273	1,696	29
2029	8,052	6,166	273	2,159	37
2030	9,474	6,202	273	3,545	60

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

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

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., +1.09% per year versus 0.09% per year compounded over the last four-year period of this review). The results show that the NPCC resource adequacy criterion is not met in all years.

2027 shows lower values in the high load case when compared to the base case due to the growth rate from the base 2026 to 2027 years being higher than the average growth rate of the total period. When adding 1.09% to 2026 high load case, to get the 2027 number, it comes out lower than the base 2027 load.

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
2026	6,178	6,178	0	0.245	0.245
2027	6,246	6,296	-50	0.208	0.269
2028	6,314	6,202	112	0.029	0.020
2029	6,384	6,166	218	0.005	0.001
2030	6,454	6,202	252	0.002	0.001

Month of January	High Load LOLH	Base Case LOLH	High Load EUE	Base Case EUE
			MWh	MWh
2026	0.580	0.580	63.76	63.76
2027	0.611	0.775	54.23	67.52
2028	0.074	0.046	1.34	0.67
2029	0.007	0.001	0.67	-
2030	0.005	0.001	-	-

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 2024 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 will rise from 1,261 MW in 2026 to 3,545 MW by the end of 2030. Simulated wind capacity during the Maritimes coincident peak demand rises from 228 MW in 2026 to 1,584 MW by 2027. The wind profile does not change throughout the study period. The load profile is non-linear, therefore the peak hour changes depending on the study year, this leads to the amount of wind on peak being not proportional to its installed capacity. 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
2026	7,253	7,366	-114	0.391	0.245
2027	7,176	7,219	-43	0.424	0.269
2028	7,513	7,625	-112	0.023	0.020
2029	7,962	8,052	-91	0.003	0.001
2030	8,682	9,474	-792	0.003	0.001

Month of January	50% Wind Derate LOLH	Base Case LOLH	50% Wind Derate EUE	Base Case EUE
			MWh	MWh
2026	0.93	0.77	105.78	63.76
2027	1.29	0.05	129.49	67.52
2028	0.06	0.00	2.54	0.67
2029	0.00	0.00	0.03	0.00
2030	0.00	0.00	0.04	0.00

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*[*] *(Approved by RCC Feb 21, 2024)* the "At Criteria" estimated tie benefit potential for the Maritimes Area is 1,286 MW in 2028 with an export of 0 MW modeled in year 2028. Based on this study, the 300 MW of tie

[*] 2023 Review of Interconnection Assistance Reliability Benefits

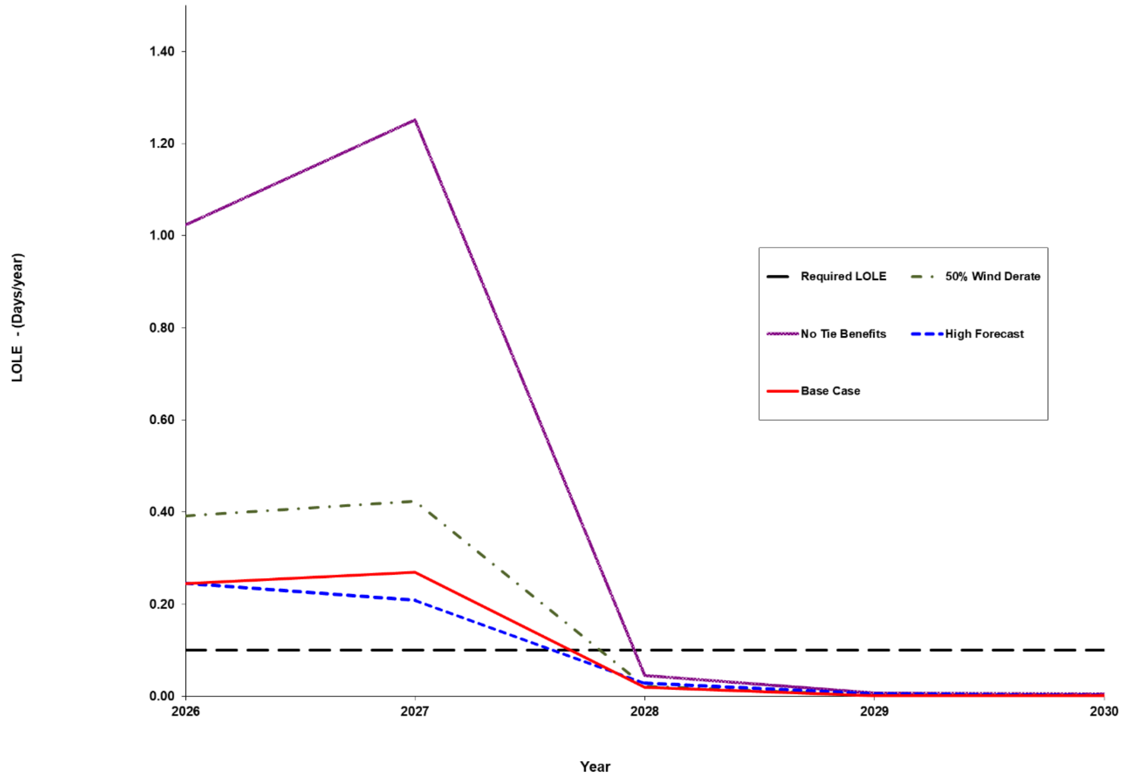
benefits assumed for this 2025 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does require interconnection assistance to meet the NPCC resource adequacy criterion in the early years of the study period. The results are shown in Table 8 and Figure 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
2026	7,066	7,366	-300	1.024	0.245
2027	6,919	7,219	-300	1.251	0.269
2028	7,325	7,625	-300	0.045	0.020
2029	7,752	8,052	-300	0.008	0.001
2030	9,174	9,474	-300	0.004	0.001

Month of January	No Tie Benefits LOLH	Base Case LOLH	No Tie Benefits EUE	Base Case EUE
			MWh	MWh
2026	3.14	0.58	397.38	63.76
2027	4.87	0.77	724.91	67.52
2028	0.11	0.05	8.86	0.67
2029	0.01	0.00	1.20	0.00
2030	0.01	0.00	0.67	0.00

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 1,261 MW in the Maritimes Area is expected at the start of 2026. Wind generation of 531 MW, 158 MW, 524 MW, 573 MW and 500 MW were added in years 2026, 2027, 2028, 2029, and 2030 respectively. A new energy storage resource of 50 MW, 150 MW, and 100 nameplate capacity was added in Nova Scotia starting in 2026, 2027, and 2029 respectively. The firm capacity contribution of this addition is 108 MW (assumes an average ELCC of 39%). Hydro imports include 153 MW firm capacity from the province of Newfoundland and Labrador.

Thermal capacity additions, retirements, and conversions are shown in Appendix A table A-3 Summary of Changes in Modeled Capacity.

4.1 Forecast Resource Capacity Mix

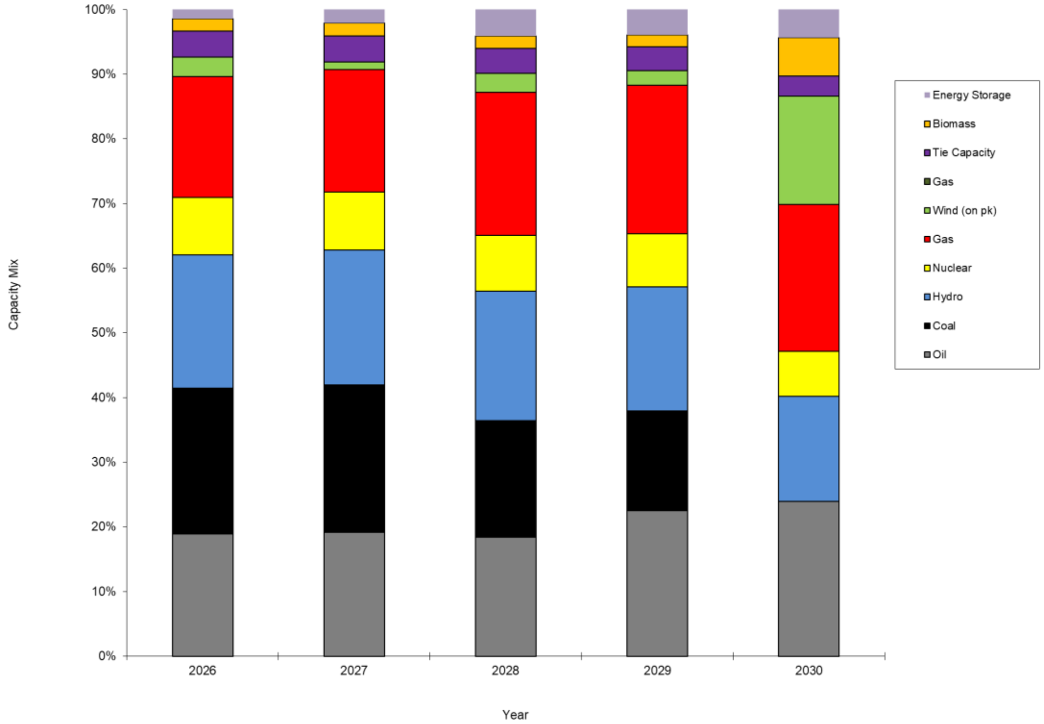
Table 9 and Figure 5 illustrate the forecast resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

Table 9: Forecast Capacity Resource Mix

Month of January	Oil	Coal	Hydro	Nuclear	Gas	Wind (on pk)	Tie Benefits	Biomass	Battery
	%	%	%	%	%	%	%	%	%
2026	19	23	21	9	19	3	4	2	1
2027	19	23	21	9	19	1	4	2	2
2028	18	18	20	9	22	3	4	2	4
2029	23	15	19	8	23	2	4	2	4
2030	24	-	16	7	23	17	3	6	4

* Wind capacity based on forecast wind production during Maritimes coincident peak

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. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions. 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. The increase will be met by wind and solar additions included in this review.

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 Calendar year 2024 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2026 to 2030 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**
2026	6,111	6,052	5,461	4,444	3,769	3,444	3,534	3,554	3,495	3,982	4,805	5,624	6,111
2027	6,157	6,085	5,498	4,474	3,786	3,455	3,552	3,578	3,514	4,010	4,840	5,662	6,157
2028	6,188	6,120	5,539	4,517	3,806	3,468	3,573	3,598	3,530	4,047	4,885	5,702	6,188
2029	6,225	6,106	5,504	4,520	3,803	3,432	3,552	3,596	3,523	3,992	4,897	5,669	6,225
2030	6,262	6,142	5,542	4,582	3,826	3,448	3,576	3,622	3,544	4,027	4,953	5,720	6,262
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2026	3,369	3,046	2,979	2,458	2,219	2,057	2,198	2,173	2,042	2,285	2,595	3,119	30,538
2027	3,405	3,077	3,008	2,487	2,246	1,966	2,110	2,089	1,965	2,201	2,510	3,036	30,100
2028	3,349	3,026	2,945	2,424	2,181	1,928	2,067	2,048	1,923	2,165	2,480	2,909	29,446
2029	3,314	2,992	2,904	2,376	2,127	1,929	2,074	2,055	1,928	2,175	2,498	3,030	29,402
2030	3,340	3,014	2,927	2,399	2,143	1,940	2,082	2,064	1,939	2,191	2,516	3,055	29,611
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2026	273	266	326	323	336	337	326	335	352	331	338	268	273
2027	273	266	326	323	336	337	326	335	352	331	338	268	273
2028	273	266	326	323	336	337	326	335	352	331	338	268	273
2029	273	266	326	323	336	337	326	335	352	331	338	268	273
2030	273	266	326	323	336	337	326	335	352	331	338	268	273

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.5 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 2026–2030 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, 2022 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, 2026				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Point Lepreau	1	Nuclear	663	
Belledune	2	Coal	466	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Bayside	6	Natural Gas	277	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	Summer Capacity = 42MW
	2	Natural Gas	49	Summer Capacity = 42MW
NUG Purchases		Biomass	38	
		Hydro	15	
Small Producers		mostly Hydro	12	
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	16.5	
	2	Hydro	16.5	
	3	Hydro	16.5	
	4	Hydro	16.5	
Tobique	1	Hydro	10	
	2	Hydro	10	
Nepisiguit Falls	1	Hydro	11	
Sisson	1	Hydro	9	
Tie Benefits			300	
NB Wind	All	Wind	26	During Maritime peak (349 MW installed)
TOTAL CAPACITY			4275.49	Total Capacity as of January 2026

Nova Scotia Resources as of January 1, 2026				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Lingan	1	Coal	150	Summer Capacity = 146 MW
	2	Coal	150	Summer Capacity = 141MW
	3	Coal	150	Summer Capacity = 146 MW
	4	Coal	150	Summer Capacity = 146 MW
Trenton	5	Coal	150	Summer Capacity = 0 MW
	6	Coal	160	Summer Capacity = 115 MW
Tupper	2	Coal	150	Summer Capacity = 145 MW
Tufts Cove	1	Gas/Oil	100	Summer Capacity = 74 MW
	2	Gas/Oil	100	Summer Capacity = 91 MW
	3	Gas/Oil	150	Summer Capacity = 144 MW
	4	Natural Gas	54	Summer Capacity = 45 MW
	5	Natural Gas	54	Summer capacity = 45 MW
	6	Natural Gas	50.8	Summer Capacity = 41 MW
Pt. Aconi	1	Coal	168	Summer Capacity = 166 MW
Burnside	1	Lt Oil	30	Summer Capacity = 25 MW
	2	Lt Oil	30	Summer Capacity = 25 MW
	3	Lt Oil	30	Summer Capacity = 25 MW
	4	Lt Oil	30	Summer Capacity = 25 MW
Victoria Junction	1	Lt. Oil	30	Summer Capacity = 25 MW
	2	Lt. Oil	30	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	24	Summer Capacity = 25 MW
NSIPP1 NUG Purchases	All	Biomass	26	
PH Biomass		Biomass	60	Summer Capacity = 43 MW
COMFIT Biomass	All	Biomass	2.5	
				All Hydro units assume an ELCC of 95%
Avon 1&2		Hydro	7	
Bear River		Hydro	10	
Black River		Hydro	23	
Dickie Brook		Hydro	4	
Fall River		Hydro	0.5	
Lequille		Hydro	11	
Morgan Falls		Hydro	1	
Mersey		Hydro	43	
Nictuax		Hydro	8	
Paradise		Hydro	5	
Sheet Harbour		Hydro	11	
Sissiboo		Hydro	27	
St. Margrets		Hydro	11	
Tusket		Hydro	2	
Wreck Cove	1	Hydro	230	
NALCOR Firm Contract		Hydro	153	
NS Wind Projects	All	Wind	85.83	During Maritime peak (631 MW installed)
TOTAL CAPACITY			2661.09	Total Capacity as of January 2026

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

Prince Edward Island Resources as of January 1, 2026				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Charlottetown	CT3	Diesel	49	Summer Capacity = 40 MW
Borden	1	Diesel	15	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside Diesels	2	Diesel	2	Owned by the City of Summerside
	3	Diesel	2	Owned by the City of Summerside
	6	Diesel	1	Owned by the City of Summerside
Energy Storage		Battery	5	
	8	Diesel	4	Owned by the City of Summerside
PEI Wind	All	Wind	89.66	During Maritime peak (200 MW installed)
TOTAL CAPACITY			192.66	Total Capacity as of January 2026

Northern Maine Resources as of January 1, 2026				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Tinker		Hydro	32.8	
Scopan		Hydro	1.4	
Woodland		Biomass	20	
NMISA Wind	All	Wind	25.95	During Maritime peak (42 MW installed)
TOTAL CAPACITY			80.15	Total Capacity as of January 2026

Table A-3: Summary of Changes in Modeled Capacity

Year	Capacity Change MW	Capacity Balance MW	Explanation Total Capacity includes installed capacity, tie benefits, firm purchases and/or sales, and planned maintenance
2026	0	7,366	Starting Capacity
2027	+ 122/-177	7,311	Removal of 122 MW sale after May, Addition of 177 MW sale starting June in NB
	-228/+85	7,168	Wind on peak for 2027, remove previous years wind on peak.
	+ 50	7,219	Addition of 50 MW battery in NS

2028	+ 177/-70	7,325	Removal of 177 MW sale after May, Addition of 70 MW sale starting June in NB
	-85/+225	7,465	Wind on peak for 2028, remove previous years wind on peak.
	+ 160	7,625	Addition of 150 MW battery in NS and 10 MW in PEI.
	+/- 300	7,625	Replacement of 300 MW of coal with 300 MW of Natural Gas in NS
2029	+ 70	7,695	Removal of 70 MW sale after May in NB
	+/- 150	7,695	Conversion of 150 MW coal to natural gas in NS
	- 225/ +182	7,652	Wind on peak for 2029, remove previous years wind on peak.
	+400	8,052	Addition of 400 MW CTs in NB
2030	+ 100	8,152	Addition of 100 MW of energy storage in NS
	+/- 450	8,152	Conversion of 450 MW of coal to oil in NS
	- 325	7,827	Retirement of 325 MW coal in NS
	+300	8,127	Addition of 300 MW natural gas in NS
	-182/ +1584	9,529	Wind on peak for 2030, remove previous years wind on peak.
	+410/-466	9,473	Conversion of 466 MW coal unit to 410 MW biomass in NB

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)	
	2025 Review*	2024 Review*
Oil	6%	5%

Coal	6%	5%
Hydro	1%	2%
Nuclear	7%	6%
Natural Gas	5%	6%
Wind	N/A	N/A
Biomass	4%	4%
Energy Storage	N/A	N/A

* Reviews based on 5-year average DAFOR calculations for FORs in NB and 3-year average DAFOR calculations for FORs in NS

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 150 MW coal in May 2027, 150 MW coal in Oct 2027, 150 MW coal in May 2028, 150 MW coal in Apr 2029, 165 MW coal in May 2029, 150 MW coal in July 2029, and 300 MW coal in Oct 2029, all in NS. Also retiring is 466 MW of coal in NB in 2029. 450 MW of coal is being converted to oil units, 150 MW of coal is being converted to natural gas and 600 MW of natural gas units are coming online in NS to offset coal retirements; the single coal unit in NB is being converted to biomass in 2029. These units along with the addition of 300 MW of batteries and wind additions will replace the dependence on coal.

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 Review of Interconnection Assistance Reliability Benefits (Approved by RCC February 21, 2024)* the "At Criteria" estimated tie benefit potential for the Maritimes Area is 1,286 MW in 2028 with an export of 0 MW modeled in year 2028. Based on this study, the 300 MW of tie benefits assumed for this 2025 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 2024 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.

Solar resources are currently limited and any new capacity that is added uses an estimated hourly solar shape for any Maritimes Area jurisdiction expressed as a percentage of the jurisdiction's total installed solar for the hour. 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 load forecasts and in the combined Maritimes Area forecast in Table A-1.

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 2025-2030 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).

APPENDIX B - DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

This multi-area analysis of resource adequacy was performed using a Monte Carlo simulation in the Energy Exemplar modelling software PLEXOS. It was modelled as follows:

- For each hourly load, generation is simulated in each jurisdiction of the Maritimes. In the case of wind generation, hourly wind generation projections 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 daily Expected Unserved Energy (EUE) is pulled to calculate if there is a Loss of Load Event event that day.
- The Monte Carlo simulation is performed for each hour of the year, and the yearly simulation is repeated 1500 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 but does not preserve the load coincidence between the jurisdictions, this changes the peak hour depending on the year.