Nova Scotia Energy Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

2025 10-Year System Outlook

NS Power

July 14, 2025

NON-CONFIDENTIAL

TABLE OF CONTENTS

1.0 Introduction....5
2.0 Load Forecast....7
3.0 Generation Resources....11
3.1 Existing Generation Resources....11
3.1.1 Maximum Unit Capacity Rating Adjustments....13
3.1.2 Mersey Hydro....14
3.1.3 Wreck Cove Hydro....14
3.2 Changes in Capacity....15
3.2.1 The Path to 2030 and Evergreen IRP....15
3.2.2 Lingan Unit 2....18
3.2.3 Annapolis Tidal....19
3.2.4 Rate Base Procurement....20
3.2.5 Green Choice Program....20
3.2.6 Additional Renewable Energy Procurements....21
3.2.7 Nova Scotia System Operator Transition – Combustion Turbines and BESS....22
3.3 Unit Utilization Forecast....23
3.3.1 Evolution of the Energy Mix in Nova Scotia....23
3.3.2 Projections of Unit Utilization....24
3.3.3 Steam Fleet Utilization Outlook....26
4.0 Queued System Impact Studies....30
4.1 System Impact Studies (SIS)....32
4.2 OATT Transmission Service Queue....33
5.0 Environmental and Emissions Regulatory Requirements....34
5.1 Renewable Electricity Requirements....34
5.2 Environmental Regulatory Requirements....35
5.2.1 Nova Scotia Greenhouse Gas Emissions Regulations....35
5.2.2 Nova Scotia Air Quality Regulations....36
5.2.3 Nova Scotia Output-Based Pricing System....37
5.2.4 Environmental Goals and Climate Change Reduction Act....38
5.3 Clean Electricity Regulations....39

6.0 Resource Adequacy ... 41
6.1 Operating Reserve Criteria ... 41
6.2 Planning Reserve Criteria ... 42
6.3 Capacity Contribution of Renewable Resources in Nova Scotia ... 43
6.4 Load and Resources Review ... 45
7.0 Transmission Planning ... 48
7.1 System Description ... 48
7.2 Transmission Design Criteria ... 49
7.2.1 Bulk Power System (BPS) ... 49
7.2.2 Bulk Electric System (BES) ... 50
7.2.3 2024 Bulk Electric System Exception Requests ... 50
7.2.4 Remedial Action Schemes (RAS) ... 51
7.2.5 NPCC Directory 1 Review ... 51
7.2.6 NPCC Directory 7 Review ... 51
7.3 Transmission Life Extension ... 52
7.4 New Large-Load Customer Interconnection Requests ... 53
7.5 Reliability Intertie ... 53
7.6 Western Valley Transmission System – Phase II Study ... 54
7.7 Hydrogen Load Impact Studies ... 54
7.8 EMT Studies to Support Wind Integration ... 55
7.9 System Inertia and Strength ... 55
7.9.1 System Inertia ... 56
7.9.2 System Strength ... 57
8.0 Transmission Development ... 58
8.1 Impact of Proposed Load Facilities ... 58
8.2 129H-Kearney Lake Relocation ... 59
8.3 Transmission Development Plans ... 59
8.4 Generator Interconnection Related Project Work ... 62
8.5 Synchronous Condenser Installations ... 63
9.0 Conclusion ... 64

LIST OF FIGURES

Figure 1: Historical and Predicted Annual Net System Requirement 8
Figure 2: Historical and Predicted Annual System Peak 9
Figure 3: Historic and Forecast Net System Requirement and System Peak 9
Figure 4: 2025 Firm Generating Capacity for NS Power and IPPs 11
Figure 5: Firm Generating Capability for Wholesale Market Participants 13
Figure 6: Firm Capacity Changes & DSM 16
Figure 7: Additions and Retirements as in the 10-Year System Outlook Resource Plan 17
Figure 8: 2005, 2024 Actual and 2026 Forecast Energy Mix 24
Figure 9: NS Power Steam Fleet Unit Utilization Forecast 24
Figure 10: Utilization Factor 26
Figure 11: Forecast Unit Utilization Factors 28
Figure 12: Forecasted Sustaining Capital Investment by Unit 29
Figure 13: Advanced Stage Interconnection Queue as of June 19, 2025 30
Figure 14: Requests in the OATT Transmission Queue as of July 03, 2025 33
Figure 15: RES Compliance Forecast 34
Figure 16: Multi-year Greenhouse Gas Emission Limits 35
Figure 17: Emissions (SO_2, NOx, Hg) 36
Figure 18: NS OBPS Emission Intensity Standards 38
Figure 19: Marginal ELCC Percentage for New Wind Additions 44
Figure 20: NS Power 10-Year Load and Resources Outlook 46
Figure 21: NS Power Major Facilities in Service 48

1.0 INTRODUCTION

Nova Scotia Power Inc. (NS Power, Company) is committed to supporting both provincial and federal targets to reach 80 percent clean energy and phasing out coal generation by 2030. Great strides have been made towards these goals over the last decade, including more than tripling the amount of renewable energy on the grid. In order to achieve next steps as part of the Province's Clean Power Plan, which is aligned with NS Power's The Path to 2030, the Company's 10-Year System Outlook report assesses system generation capacity, considering load forecasts, planned generation additions, and environmental regulations, while adhering to the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

In accordance with the Nova Scotia Wholesale and Renewable to Retail Electricity Market rule requirement 3.4.2 - Scope of the Nova Scotia Power System Operator (NSPSO) system plan[1], this report provides the 10-Year System Outlook report (Report) on behalf of the Nova Scotia Power System Operator (NSPSO) for 2025. The 10-Year System Outlook is not an integrated resource planning exercise. It is the NSPSO's annual assessment of NS Power's system capacity and resource adequacy.

The Report contains the following information:

- A summary of the NS Power load forecast in **Section 2.0**.

- A summary of generation expansion anticipated for facilities owned by NS Power and others in **Section 3.0**. This section also includes details about NS Power's generation planning for existing facilities, including retirements, investments in upgrades,

[1] Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules (as amended 2016 06 10), Market Rule 3.4.2 states, "The NSPSO system plan will address: (a) transmission investment planning; (b) DSM programs operated by EfficiencyOne or others; (c) NS Power generation planning for existing Facilities, including retirements as well as investments in upgrades, refurbishment or life extension; (d) new Generating Facilities committed in accordance with previous approved NSPSO system plans; (e) new Generating Facilities planned by Market Participants or Connection Applicants other than NS Power; and (f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services)."

refurbishment or life extension, and new generating facilities committed in accordance with previously approved NSPSO system plans.

- An updated list of Queued System Impact Studies in **Section 4.0**.

- A summary of environmental and emissions regulatory requirements, as well as compliance in **Section 5.0**. This section also includes projections of the level of renewable energy forecast and discusses anticipated policy changes.

- A Resource Adequacy Assessment in **Section 6.0**.

- A discussion of transmission planning considerations in **Sections 7.0** and **8.0**.

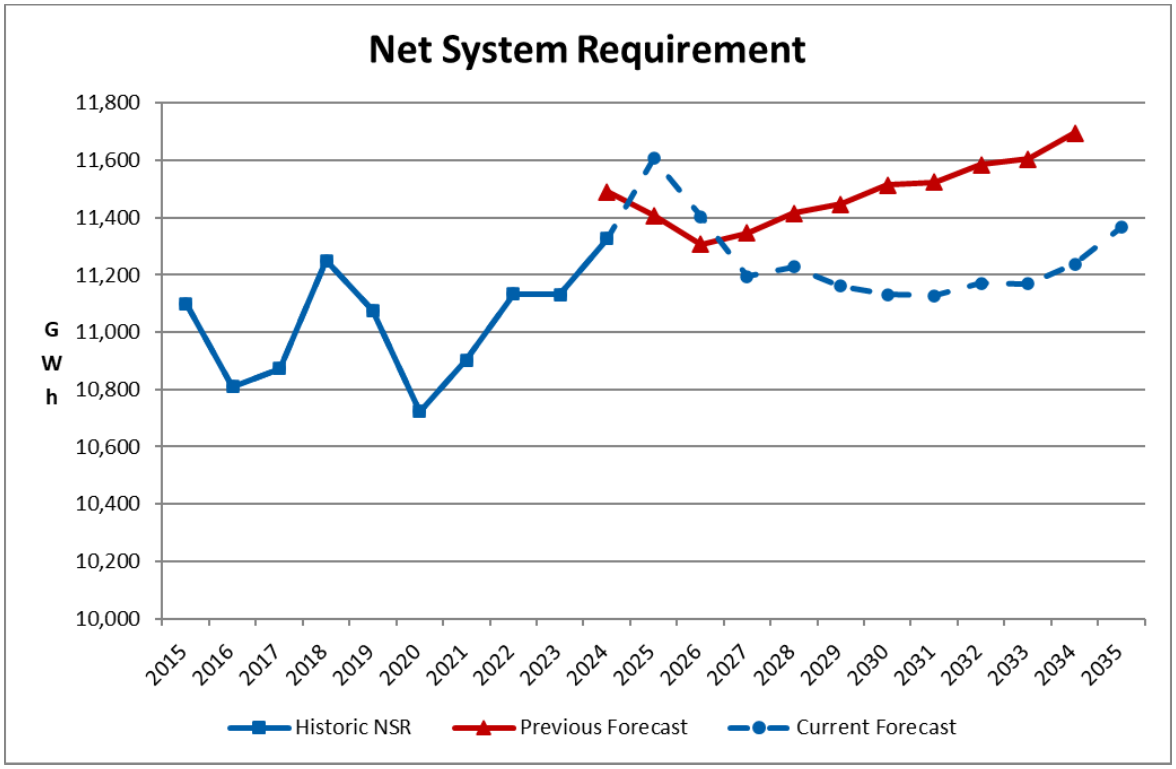
Last year's 2024 10-Year System Outlook report reflected updates from NS Power's Evergreen IRP Updated Action Plan and Roadmap, the Province of Nova Scotia's 2030 Clean Power Plan, and NS Power's The Path to 2030 report. The resource plan presented in the 10-Year System Outlook report was a combination of Evergreen IRP scenario CE1-E1-R2 in conjunction with specific projects with known timelines from the 2030 Clean Power Plan and NS Power's The Path to 2030. Since then, work has continued to advance under the Province of Nova Scotia's Clean Power Plan. In addition, an application has been submitted to the Nova Scotia Energy Board (NSEB, Board) for the construction of the NS-NB Reliability Intertie. The 2025 10-Year System Outlook report incorporates the progress on these initiatives and presents a resource plan which continues to align with the Path to 2030 for the years 2025 to 2030 and the Evergreen IRP Scenario CE1-E1-R2 for the years after 2030.

2.0 LOAD FORECAST

NS Power continues to use and refine Statistically Adjusted End-Use (SAE) models to forecast load for the residential and commercial rate classes. The SAE models explicitly incorporate end-use energy intensity projections into the Load Forecast. End-use energy forecasts derived from the residential and commercial SAE models are then combined with an econometric-based industrial forecast and customer specific forecasts for NS Power's large customers to develop an energy forecast for the province, also referred to as the Net System Requirement (NSR). Potential new large projects are discussed in **Section 7.4**, but are not part of the underlying load forecast (they are provided as sensitivities).

Compared to the 2024 Load Forecast, the 2025 Load Forecast shows an increased net system requirement in the near term due to a change in forecast for Renewable to Retail (RTR) sales. Mid- to long-term growth is lower in the 2025 Load Forecast, driven by reduced estimates for Electric Vehicle (EV) sales, increased sales through the RTR market, and increased behind the meter solar, offsetting continued customer growth and continued electrification of space and water heating. In the long term, energy sales will also be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs. The net result is a forecast average annual decrease of 0.2 percent between 2025 and 2035. Annual historic and forecast NSR are shown below in **Figure 1.**

Figure 1: Historical and Predicted Annual Net System Requirement



In addition to annual energy requirements, NS Power forecasts system peak demand. Customer growth, electrification of heating and increased EV sales will increase the peak, while DSM and DR activities will reduce the peak. Compared to 2024, the peak forecast is very similar in the near term (the change in RTR forecast does not impact the peak forecast as there is no decrease to the supply requirements associated with RTR peak demand) and slightly lower in the long term due to a revised EV peak impact. As a result, the system peak demand is expected to increase at an average of 1.1 percent annually over the forecast period, as shown in **Figure 2.**

Figure 2: Historical and Predicted Annual System Peak

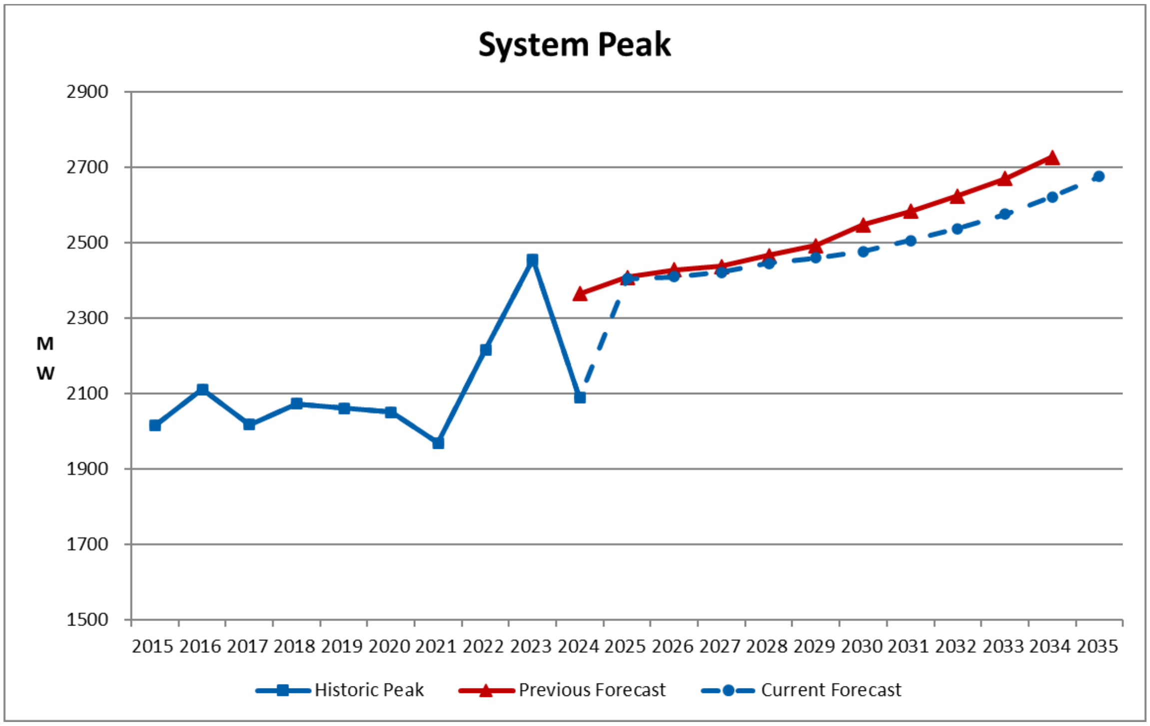


Figure 3 below shows the changes to system load and system peak over the historic and forecast periods.

Figure 3: Historic and Forecast Net System Requirement and System Peak

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2015	11,099	0.6	2,015	-4.9
2016	10,809	-2.6	2,111	4.8
2017	10,873	0.6	2,018	-4.4
2018	11,250	3.5	2,073	2.7
2019	11,077	-1.5	2,060	-0.6
2020	10,723	-3.2	2,050	-0.5
2021	10,902	1.7	1,968	-4.0
2022	11,134	2.1	2,216	12.6
2023	11,131	0.0	2,455	10.8
2024	11,326	1.8	2,088	-14.9
2025F	11,607	2.5	2,403	15.1
2026F	11,403	-1.8	2,408	0.2
2027F	11,193	-1.8	2,423	0.6
2028F	11,226	0.3	2,443	0.8

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2029F	11,159	-0.6	2,458	0.6
2030F	11,130	-0.3	2,474	0.7
2031F	11,125	0.0	2,503	1.2
2032F	11,169	0.4	2,535	1.3
2033F	11,168	0.0	2,573	1.5
2034F	11,236	0.6	2,618	1.8
2035F	11,365	1.1	2,672	2.0

3.0 GENERATION RESOURCES

3.1 Existing Generation Resources

NS Power's generation portfolio is composed of a mix of fuel and technology types that include coal, petroleum coke, light and heavy fuel oil, natural gas, biomass, wind, hydro and solar. In addition, NS Power purchases energy from Independent Power Producers (IPPs) located in the province and imports power across the Nova Scotia / New Brunswick intertie and the Maritime Link, a DC link between Nova Scotia and Newfoundland. Since the implementation of the Renewable Electricity Standards (RES) discussed in **Section 5.1**, an increased percentage of total energy is produced by variable renewable resources such as wind. However, due to their intermittent nature, these variable resources provide less firm capacity, as a percentage of net operating capacity, than conventional generation resources. Therefore, the majority of the system requirement for firm capacity is met with NS Power's conventional units (e.g. coal, gas, hydro, biomass) while their energy output is displaced by variable renewable resources (e.g. wind, solar).

Figure 4 lists NS Power's and the IPPs' verified and forecast firm generating capability for generating stations/systems along with their fuel types up to the filing date of this Report. The changes and additions over the 10-year period to this total capacity are shown in **Figure 6 (Section 3.2**). The firm generating capability for the wholesale market participants is set out in **Figure 5.**

Figure 4: 2025 Firm Generating Capacity for NS Power and IPPs

Plant/System	Fuel Type	Winter Net Capacity (MW)
Avon	Hydro	6.4
Black River	Hydro	21.4
Lequille System	Hydro	23.0
Bear River System	Hydro	35.5
Tusket	Hydro	2.3

Plant/System	Fuel Type	Winter Net Capacity (MW)
Mersey System[2]	Hydro	34.9
St. Margaret's Bay	Hydro	10.3
Sheet Harbour	Hydro	10.2
Dickie Brook	Hydro	3.6
Wreck Cove	Hydro	201.4
Annapolis Tidal[3]	Hydro	0.0
Fall River	Hydro	0.5
NS Base Block	Hydro	145.4
Total Hydro		**494.8**
Tufts Cove	Heavy Fuel Oil/Natural Gas	318
Trenton	Coal/Pet Coke/Heavy Fuel Oil	304
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	150
Lingan[4]	Coal/Pet Coke/Heavy Fuel Oil	607
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	168
PH Biomass		43
Total Steam		**1590**
Tufts Cove Units 4, 5 & 6	Natural Gas	144
Total Combined Cycle		**144**
Burnside	Light Fuel Oil	132
Tusket	Light Fuel Oil	33
Victoria Junction	Light Fuel Oil	66
Total Combustion Turbine		**231**
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.7
Post-2001 Renewables (firm)	IPPs	64.3
NS Power wind (firm)	Wind	14.5

[2] The Effective Load Carrying Capability (ELCC) for Mersey has been maintained at 82 percent in the 2025 10-Year System Outlook.
[3] Annapolis is assumed to be out of service. Please refer to Section 3.2.3
[4] Lingan Unit 2 will be retained in cold reserve in order to provide firm capacity for the winter peak until it is retired in 2027. Please refer to Section 3.2.2.

Plant/System	Fuel Type	Winter Net Capacity (MW)
Community-Feed-in-Tariff (firm)[5]	IPPs	29.6
Tidal IPP	Tidal	0.0
NS Power solar & Community solar (firm)	Solar	0.1
Total IPPs & Renewables		**134.2**
Total Capacity (NS Power and IPPs)		**2593.9**

Figure 5: Firm Generating Capability for Wholesale Market Participants

Wholesale Market Participant	Fuel Type	Winter Net Capacity[6] (MW)
Backup Top-Up (BUTU) [7]	Wind [Ellershouse] [8]	4.2
Total		**4.2**

3.1.1 Maximum Unit Capacity Rating Adjustments

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NS Power meets the requirement for generator capacity verification as outlined in North American Electric Reliability Corporation (NERC) Standard MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability[9] which was approved by Federal Energy Regulatory Commission (FERC) on March 20, 2014 and approved by the NSEB for effect in the province on July 1, 2016.

The Net Operating Capacity of the thermal units and large hydro units covered by the NERC

[5] Existing Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service. (NRIS) wind projects are assumed to have a firm capacity contribution of 18 percent as detailed in Section 6.3.

[6] NSUARB Backup/Top-up Service (BUTU) Decision (M09940), page 38: to use 18 percent ELCC for wind and 0 percent for non-firm Imports to align with current NS Power planning practices.

[7] Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.

[8] Ellershouse wind farm is owned by the Alternative Resource Energy Authority (AREA).

[9] https://www.nerc.com/pa/Stand/Pages/Project2007-09-Generator-Verification.aspx

criteria are current. NS Power will continue to update unit maximum capacities in the 10-Year System Outlook each year as operational conditions change.

3.1.2 Mersey Hydro

The Mersey Hydro System (MHS) provides significant value to customers with a capacity of 42.5 MW, and an annual contribution of approximately 220 GWh toward NS Power's renewable energy targets. As NS Power progresses toward 80 percent renewable electricity sales by 2030, sustaining investment in the MHS supports both capacity and renewable energy generation, contributing to system reliability amid increasing wind generation.

NS Power's 2025 ACE Plan and The Path to 2030 included sustaining capital investments in the MHS to ensure the safe and reliable water management of the system while work is completed to inform the decision on whether to redevelop or decommission the MHS. These sustaining investments are necessary regardless of the ultimate decision and are aligned with NS Power's asset management principles.

3.1.3 Wreck Cove Hydro

The Wreck Cove Hydro system is an important asset for NS Power, providing critical and renewable generation for peak demand periods. With the ability to quickly provide 212 MW of peak capacity from two operating units and average annual generation of 300 GWh, Wreck Cove is NS Power's largest hydroelectric system. As part of the Life Extension and Modernization (LEM) Project, both unit turbines will be replaced with newly designed turbine runners which will have increased efficiency and a wider operating range over the existing ones. Unit 1 returned to service in 2024, and Unit 2 is currently under construction. While the change in turbine runners will not change the peak capacity of 212 MW, it will provide a forecast increase of 5 percent to the annual generation from Wreck Cove. The completion of this project will bring the average annual generation at Wreck Cove to 315 GWh per year.

As of the writing of the 2025 10-Year System Outlook report, the project schedule for the LEM Project anticipates a return to service for Wreck Cove Unit 2 in Q1 2026. This is a delay in timing when compared to the 2024 10-Year System Outlook which anticipated Unit 2 would return to service in advance of the 2025/2026 Winter period. This schedule is reflected in **Figure 20.** Further updates on this project can be found in the quarterly contingency and cost minimization reports filed as part of M09596.

3.2 Changes in Capacity

3.2.1 The Path to 2030 and Evergreen IRP

The 2025 10-Year System Outlook report resource plan continues to align with the Province of Nova Scotia's 2030 Clean Power Plan and NS Power's Evergreen IRP scenario CE1-E1-R2 (net zero 2035, current policy and trends electrification, no Atlantic Loop). This resource mix enables NS Power and the Province of Nova Scotia's goals of decarbonizing, phasing out coal generation, and reaching 80 percent renewable energy generation by 2030. The resource plan is summarized in **Figure 6,** which presents anticipated DSM and firm capacity changes and **Figure 7** which outlines the anticipated system additions and retirements over the 2026-2035 period. Each year since the release of the Province of Nova Scotia's 2030 Clean Power Plan was released, NS Power has filed The Path to 2030 alongside the ACE Plans, which include updates on the new resources to be added to the system. These updates are reflected in **Figure 6** and **Figure 7**.

Many of the resource additions are in a development stage, so there will continue to be adjustments in timing for planned in-service and corresponding retirement dates. NS Power also continues to monitor changes in the electricity planning environment and developments of emerging technologies (hydrogen-fueled combustion turbines, small modular nuclear reactors, tidal, natural gas generation with carbon capture storage, geothermal, and long duration energy storage) and reassess the resource plan as needed.

1 **Figure 6: Firm Capacity Changes & DSM**

New Resources 2026-2035	Net MW
DSM Peak reduction	234
Demand Response (Firm contribution)[10]	37
Total Demand Side MW Change Projected Over Planning Period	**271**
Maintenance/Repairs:	
Hydro derates during Wreck Cove LEM	-101
Wreck Cove LEM Completion	101
Additions:	
New Wind Build - Rate Base Procurement (Firm Capacity)	31
New Wind Build - Green Choice Program (Firm Capacity)	21
New Wind Build - Port Hawkesbury Paper Wind & Minas Highlands (Firm Capacity)	18
New Wind Build – Future Procurements (Firm Capacity)[11]	97
New Renewable to Retail Wind	15
Battery (Firm Capacity)	180
Diversity Credit (Solar + Battery Energy Storage System)	12
Point Tupper 2 Coal-to-Gas conversion	150
Fast Acting Generation	600
Additions - Coal to HFO Operation (Lingan 1, 3 & 4 Conversions)	459
Retirements:	
Trenton 5 & 6	-304
Lingan 1, 3 & 4 (Coal Operation), Lingan 2	-607
Point Tupper (Coal Operation)	-150
Point Aconi	-168
Total Firm Supply MW Change Projected over Planning Period	**354**

2
3

[10] Represents the firm contribution of demand response programs in 2035 assuming an ELCC of 48 percent.
[11] Represents additional wind projects above and beyond the Rate Based Procurement Program, Green Choice Program, Port Hawkesbury Paper Wind and Minas Highlands Wind from 2029-2034 in alignment with Evergreen IRP Scenario CE1-E1-R2.

Figure 7: Additions and Retirements as in the 10-Year System Outlook Resource Plan

Winter	Additions					Retirements	
	Generation Type	Name	Installed Capacity (MW)	Firm Capacity (MW)	Diversity Credit (MW)	Name	Retired Capacity (MW)
2025/ 2026	Wind[12]	Rate Base Procurement	128	13			
	Battery Storage[13]	NS Power BESS	100	72			
2026/ 2027	Wind	Rate Base Procurement	178	18			
	Wind	Renewable to Retail	90	9			
	Wind	Port Hawkesbury Paper Wind	168	17			
	Wind	Minas Highlands Wind	13	1			
	Battery Storage	NS Power BESS	50	24			
	Solar	NS Community Solar	25	0	3		
2027/ 2028	Wind	Renewable to Retail	59	6		Trenton 5	150
	Combustion Turbine	Nova Scotia Independent Energy System Operator (NSIESO) Fast Acting CTs	300	300		Lingan 2	148
	Battery Storage	NSIESO BESS	150	49			
	Solar	NS Community Solar	25	0	3		
2028/ 2029	Coal-to-Gas	Point Tupper 2 Coal-to-Gas Conversion	150	150		Point Tupper 2	150
	Wind	Green Choice	262	21			
	Solar	NS Community Solar	25	0	3		
2029/ 2030	Battery Storage	NSIESO BESS	100	36		Lingan 1, 3, 4	459
	Combustion Turbine	NSIESO Fast Acting CTs	300	300		Point Aconi	168
	Coal-to-HFO	Lingan 1, 3, 4 Coal to HFO Operation	459	459		Trenton 6	154

[12] Refer to Figure 19: Marginal ELCC Percentage for New Wind Additions for the marginal ELCC percentage applied to new wind additions in each period.
[13] Battery Storage ELCC Percentage based on results of Planning Reserve Margin and Capacity Value Study, July 2019 by Energy and Environmental Economics, Inc.

Winter	Additions					Retirements	
	Generation Type	Name	Installed Capacity (MW)	Firm Capacity (MW)	Diversity Credit (MW)	Name	Retired Capacity (MW)
	Solar	NS Community Solar	25	0	3		
	Wind	Future Procurements	350	28			
2030/ 2031	Wind	Future Procurements	300	24			
2031/ 2032	Wind	Future Procurements	200	12			
2032/ 2033	Wind	Future Procurements	200	12			
2033/ 2034	Wind	Future Procurements	200	12			
2034/ 2035	Wind	Future Procurements	150	9			

3.2.2 Lingan Unit 2

Effective August 15, 2022, Lingan Unit 2 was no longer made available for economic dispatch. The unit was placed into cold reserve and available to be recalled on two weeks' notice. Over the 2024/2025 Winter period the unit was recalled to service four times by the NSPSO to support firm customer load, generating a total of 128 GWh.

In the 2024 10-Year System Outlook, NS Power identified a need to continue to retain Lingan 2 in cold reserve to provide firm capacity due to an increase in forecast firm peak demand (**Section 2.0**). The 2025 10-Year System Outlook continues to identify a requirement for this firm capacity. Lingan 2 will therefore continue to be held in cold reserve to maintain planning reserve margin until new firm fast acting generation resources, procured by the NSIESO, are online and have demonstrated reliable operation. See **Section 6.2** for additional details.

As new firm capacity resources are added to the system, retaining existing thermal units in cold reserve can support commissioning, testing and establishment of reliable operations without compromising the planning reserve margin requirements. This will be considered and assessed as plans for new resources are progressed.

3.2.3 Annapolis Tidal

The Annapolis Tidal Generating Station ceased generation in January 2019 following the failure of a crucial station component. Subsequently, NS Power completed an analysis to determine whether continued reinvestment in the facility was the lowest cost option for customers. Ultimately, NS Power made the determination that the facility should be retired. In February 2021, NS Power applied to the NSEB[14] for approval to treat the generating station as Not Used and Not Useful in accordance with approved accounting policies, and for approval to amortize the unrecovered net book value of the assets over a 10-year period. On January 14, 2022, the Board concluded that it was not yet in a position to find the asset Not Used and Not Useful. The Board indicated that it felt the accounting treatment of the Generating Station was best addressed as part of a decommissioning application, however it did not specifically direct the Company on how to proceed in a future application. NS Power is continuing capital planning activities with respect to the future of the generating station.

NS Power provided a status update to the NSEB on March 9, 2023 indicating that the Company, along with the relevant environmental regulators (DFO), continues to assess the Annapolis Tidal Generating Station. NS Power has provided bi-annual updates to the NSEB, with the most recent update provided on January 30, 2025. In the update, NS Power provided further detail about the assessment of requirements to either return the plant to operation or decommission. Engineering and environmental studies continue, and the Options Analysis is being updated regarding the future of Annapolis Tidal Generating Station. Another update will be provided to the NSEB on July 31, 2025. For the purposes of the 2025 10-Year System Outlook report, NS Power has assumed no capacity or energy contribution from the Annapolis Tidal Generating Station.

---

[14] NS Power Application re Annapolis Tidal Generation Station Retirement: Request for Accounting Treatment and Net Book Value Recovery (M10013, P-111.6), February 22, 2021.

3.2.4 Rate Base Procurement

The RBP Program is made up of four (4) projects totaling 306 MW and 1,165 GWh of wind generation. The projects are:[15]

- Interconnection Request (IR) 673 – Benjamins Mill Wind near Falmouth in Hants County, developed by Natural Forces Development and Wskijnu'k Mtmo'taqnuow Agency Ltd, an organization which represents the 13 Mi'kmaw Nations in the province.

- IR 669 – Higgins Mountain Wind Farm near Wentworth in Colchester and Cumberland counties, developed by Elemental Energy and Sipekne'katik First Nation.

- IR 668 – WEB Weavers Mountain Wind near Marshy Hope in Pictou and Antigonish counties, developed by SWEB Development and Glooscap First Nation

- IR 667 – Wedgeport Wind Farm in Yarmouth Cunty, developed by Elemental Energy and Sipekne'katik First Nation

Benjamin Mills Wind and Higgins Mountain Wind Farm are anticipated to be in service by the end of 2025. The remainder of the projects are expected to be in service by December 31, 2026. These timelines are reflected in **Figure 7** and **Figure 20**.

3.2.5 Green Choice Program

The Green Choice Program (GCP) was established by the Province of Nova Scotia in April 2022 following amendments to the Electricity Act.[16] The goal of the GCP is for the Province to procure a minimum of 1,500 GWh, and up to 2,000 GWh, of new low-impact renewable electricity for which large scale energy customers can contract to achieve their greenhouse gas emissions

[15] https://novascotiarbp.com/updates
[16] S.N.S. 2022, c. 12.

reduction targets while supporting the Province's 2030 decarbonization goals per section 6B(3)(a) of the Renewable Electricity Regulations and per section 24 of the GCP Regulations. The Province's Procurement Administrator, Coho, issued the RFP associated with the GCP on December 1, 2023. In January 2025, six (6) wind farms were chosen through the procurement process and awarded the opportunity to execute a PPA with NS Power. In June 2025, two (2) wind farms with a combined total capacity of 262 MW signed their awarded Power Purchase Agreements (PPA). Per communications from Coho, any proponent who did not execute the Green Choice PPA by June 13, 2025 is considered withdrawn.

3.2.6 Additional Renewable Energy Procurements

The Path to 2030 identified that additional renewable energy procurements may be necessary in order to meet the 2030 80 percent renewable energy standards.[17] Based on current procurement results, an additional 350 MW of new wind generation capacity is required and has therefore been added to the resource outlook coming online for Winter 2029/2030, which would need to be procured and awarded in a future procurement. These quantities and timelines are reflected in **Figure 7** and **Figure 20**.

With all in-progress resource additions and the additional 350 MW wind procurement requirement referenced above, the RES compliance forecast for 2030, shown in **Figure 15**, shows the system meeting the 80 percent compliance threshold. NS Power currently understands that the government and/or the NSIESO are responsible for future renewable energy procurements if needed. This update in accountabilities was reflected in The Path to 2030 – 2024 Update. In order to meet the 2030 decarbonization timelines, NS Power, in its current function as System Operator, recommends a new procurement process should commence before the end of 2025, targeting 1,000 – 1,200 GWh of low-impact renewable electricity.

[17] M12012, 2025 Annual Capital Expenditure Plan, Appendix H, Section 6.1.7 Additional Renewable Energy Procurements.

3.2.7 Nova Scotia System Operator Transition – Combustion Turbines and BESS

The 2024 10-Year System Outlook report included 600 MW of new fast-acting generation to be installed by 2030 to provide firm capacity to maintain supply reliability while meeting growing peak demand requirements, and to replace firm capacity that will be retired to comply with the 2030 coal phase-out policy requirements. 2030 is also a key date for the Clean Electricity Regulations (CER) as the pool size for the sharing of compliance credits is based on thermal capacity commissioned before January 1, 2030. Having new thermal capacity online before 2030 creates more flexibility for the system to maintain compliance with CER and minimizes costs for customers.

The inclusion of 600 MW of fast-acting generation in the resource plan is consistent with the Province's 2030 Clean Power Plan, NS Power's The Path to 2030, and the 2023 Evergreen IRP. NS Power had been developing a 300 MW fast-acting generation project in alignment with both the 2030 Clean Power Plan and the IRP Action Plan with an expected in-service date of 2027. In the Fall of 2024, the Department of Natural Resources and Renewables informed NS Power that procurement of all new fast acting generation will be the responsibility of the NSIESO, including responsibility for the first 300 MW of generation. This update in accountabilities was reflected in The Path to 2030 – 2024 Update.[18]

In the 2025 10-Year System Outlook report, capacity and timing have been assumed to be the same as the 2024 10-Year System Outlook report, until NS Power receives an update from the NSIESO on its expectations regarding capacity and timing of new fast-acting generation. It is NS Power's current understanding that recent directional changes will have a material impact on the timing set out in the Path to 2030 given the lead times seen across the industry for new combustion turbines and that it is increasingly unlikely any new fast-acting generation units will be online by Winter 2027-28. A delay in timing will mean that all 600 MW of new fast-acting generation will need to be procured and built at the same time as opposed to the two-stage approach originally planned for

[18] M12012 NS Power 2025 ACE Plan Application, Exhibit N-1(viii), Appendix H – Path to 2030 Update, December 9, 2024.

within the 2030 Clean Power Plan, NS Power's The Path to 2030, and the 2023 Evergreen IRP. Planned coal capacity retirement dates will subsequently need to be adjusted in order to maintain system reliability and NPCC compliance.

In the 2024 10-Year System Outlook report, NS Power anticipated up to 150 MW of energy storage capacity may be designated by the Province under Section 4D and an additional 100 MW of energy storage capacity would be procured by the Province under Section 4B of the *Electricity Act.*[19] The Province has since confirmed that all future energy storage capacity additions will be procured by the NSIESO. In the 2025 10-Year System Outlook, capacity and timing has been assumed to be the same as the 2024 10-Year System Outlook and is identified in **Figure 7** as "NSIESO BESS." The capacity and timing of future energy storage capacity will be determined and updated by the NSIESO.

3.3 Unit Utilization Forecast

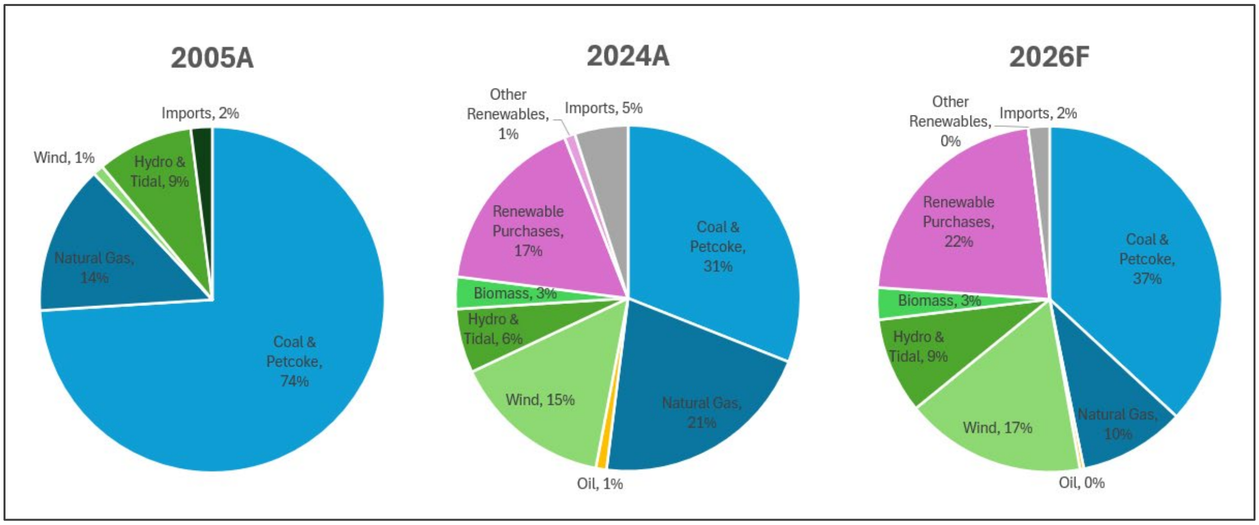
The Company typically forecasts ten years of utilization and investment projections in this Report. These projections inform NS Power's asset planning approach and are used to guide investment strategies. There are many operational factors, such as the prices of fuel and power or changes in policy, electricity demand, or regulation that could trigger a significant shift in the utilization forecast to provide the most economic system dispatch for customers.

3.3.1 Evolution of the Energy Mix in Nova Scotia

NS Power's energy production mix has undergone significant changes over the last 15 years. As discussed in **Section 3.1**, variable renewable energy resources are producing more of the overall energy mix than in the past. **Figure 8** below illustrates this change with the actual energy mix from 2005 and 2024 and the updated forecast for 2026.

[19] S.N.S. 2023, c. 17.

Figure 8: 2005, 2024 Actual and 2026 Forecast Energy Mix



3.3.2 Projections of Unit Utilization

NS Power's projected utilization of each of the units in the thermal generating fleet is set out below in **Figure 9.**

Figure 9: NS Power Steam Fleet Unit Utilization Forecast

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Lingan 1[20]	Capacity Factor (%)	41	29	31	27	1	1	2	1	1	0
	Unit Cycles	9	17	16	8	6	4	5	5	6	0
	Service Hours	4475	3364	3417	791	116	103	183	142	107	0
Lingan 2[21]	Capacity Factor (%)	0	0	0	0	0	0	0	0	0	0
	Unit Cycles	0	0	0	0	0	0	0	0	0	0
	Service Hours	0	0	0	0	0	0	0	0	0	0
Lingan 3	Capacity Factor (%)	70	52	20	23	1	2	2	2	1	0
	Unit Cycles	4	5	25	12	7	8	10	7	6	0
	Service Hours	6964	5821	2157	1043	171	209	273	242	172	0
Lingan 4	Capacity Factor (%)	60	53	31	25	2	1	2	2	2	0
	Unit Cycles	8	11	25	15	5	6	7	7	8	0
	Service Hours	6313	5771	3342	880	176	182	247	222	179	0

[20] Lingan units 1, 3, 4 operate on HFO from 2030-2035.
[21] Lingan unit 2 will be held in cold reserve, recallable to service as needed until replacement firm capacity is online. See Section 3.2.2**.**

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Point Aconi	Capacity Factor (%)	61	41	12	15	0	0	0	0	0	0
	Unit Cycles	14	5	5	3	0	0	0	0	0	0
	Service Hours	6182	4067	1264	481	0	0	0	0	0	0
Point Tupper[22]	Capacity Factor (%)	47	37	21	25	2	1	2	2	2	2
	Unit Cycles	13	13	3	14	8	9	10	5	9	6
	Service Hours	4805	4133	674	2923	254	161	270	219	232	181
Trenton 5	Capacity Factor (%)	10	8	0	0	0	0	0	0	0	0
	Unit Cycles	4	2	0	0	0	0	0	0	0	0
	Service Hours	1131	894	0	0	0	0	0	0	0	0
Trenton 6	Capacity Factor (%)	40	27	48	13	0	0	0	0	0	0
	Unit Cycles	4	12	23	11	0	0	0	0	0	0
	Service Hours	4283	2795	4722	1024	0	0	0	0	0	0
Tufts Cove 1	Capacity Factor (%)	4	4	11	18	5	3	5	4	2	0
	Unit Cycles	4	3	11	34	14	7	12	11	7	2
	Service Hours	448	570	1017	1688	447	285	467	367	207	24
Tufts Cove 2	Capacity Factor (%)	14	12	35	37	20	16	17	12	12	5
	Unit Cycles	24	23	30	61	62	65	46	45	56	16
	Service Hours	1581	1452	3534	3562	2142	1676	1679	1240	1235	441
Tufts Cove 3	Capacity Factor (%)	18	15	42	54	30	23	28	21	18	11
	Unit Cycles	31	38	35	55	89	83	80	79	71	47
	Service Hours	2138	1896	4221	5442	3340	2525	3067	2322	1914	1201
Tufts Cove 4	Capacity Factor (%)	67	62	80	80	62	56	57	43	39	32
	Unit Cycles	123	151	84	81	222	214	209	206	224	218
	Service Hours	6183	5711	7287	7279	5822	5240	5355	4051	3677	2942
Tufts Cove 5	Capacity Factor (%)	77	71	82	80	62	55	57	44	38	31
	Unit Cycles	51	73	77	83	237	221	206	218	250	227
	Service Hours	6965	6572	7419	7258	5827	5186	5379	4120	3551	2913
Tufts Cove 6	Capacity Factor (%)	30	29	59	61	45	40	41	34	30	22
	Unit Cycles	43	60	49	55	161	159	145	161	175	169
	Service Hours	6742	6701	6986	6884	5598	5074	5225	4082	3501	2868
PH Biomass	Capacity Factor (%)	53	53	58	63	66	60	45	36	46	47
	Unit Cycles	100	96	171	156	160	175	193	204	219	220
	Service Hours	5758	5774	5930	6065	6522	5957	4812	4045	4868	4494

[22] Point Tupper is converted to Natural Gas in 2028.

3.3.3 Steam Fleet Utilization Outlook

Unit utilization and reliability objectives have long been the drivers for unit investment planning. Traditionally, in a predominantly base-loaded generation fleet, it was sufficient to consider capacity factor as the source for utilization forecasts for any given unit. This is no longer the case; integration of variable renewable resources on the NS Power system has imposed revised operating and flexibility demands to integrate wind generation on previously base-loaded steam units. Therefore, it is also necessary to consider the effects of unit starts, operating hours, flexible operating modes (e.g. ramping and two-shifting) and asset health along with the forecast unit capacity factors.

NS Power created the concept of utilization factor (UF) for the purpose of providing a directional understanding of the future use of each generating unit. This approach enables the Company to better demonstrate the demands placed upon NS Power's generating units given their planned utilization. The UF for each unit is evaluated by considering the forecast capacity factor, annual operating hours, unit starts, expected two-shifting, and a qualitative evaluation of asset health. By accounting for these operational capabilities, the value brought to the power system by these units is more clearly reflected. Please refer to **Figure 10** below.

Figure 10: Utilization Factor

The UF parameters are assessed to more completely describe the operational outlook for the steam fleet and direct investment planning. The four parameters are described below.

- Capacity factor reflects the energy production contribution of a generating unit and is a necessary constituent of unit utilization. It is a part of the utilization factor determination rather than the only consideration, as it would have been in the past.

- Service hours have become a more important factor to consider with increased penetration of variable-intermittent generation, as units are frequently running below their full capacity while providing load following and other essential reliability services for wind integration. For example, if a unit operates at 50 percent of its capacity for every hour of the year, then the capacity factor would be 50 percent. In a traditional model, this would suggest a reduced level of investment required, commensurate with decreased capacity factor. However, many failure mechanisms are a function of operating hours (e.g. turbines, some boiler failure mechanisms, and high energy piping) and the number of service hours (which in this example is every hour of the year) is not reflected by the unit's capacity factor. Additionally, some failure mechanisms can be exacerbated by reducing load operation (e.g. valves, some pumps, throttling devices).

- Unit cycling increases damage mechanisms on many components (e.g. turbines, motors, breakers, and fatigue in high energy piping systems) and accelerates failure mechanisms; therefore, these must also be considered to properly estimate the service interval and appropriate maintenance strategies.

- Asset health is a critical operating parameter to keep at the forefront of all asset management decisions. For example, asset health may determine if a unit is capable of two-shifting (unit is shut down during low load overnight and restarts to serve load the next day). Although it does not necessarily play directly into the UF function, it can be a dominant determinant in allowing a mode of operation; therefore, it influences the UF function.

While the UF rating provides a directional understanding of the future use of each generating unit, the practice of applying it has another layer of sophistication as system parameters change. NS Power utilizes outputs from the PLEXOS dispatch optimization model to derive utilization forecasts and qualitatively assess the UF of each unit by evaluating the components described above**. Figure 11** below provides the UF by each unit on an annual basis.

Figure 11: Forecast Unit Utilization Factors[23]

Unit	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LIN-1	M	M	M	UL	UL	UL	UL	UL	UL	UL
LIN-3	H	H	L	L	UL	UL	UL	UL	UL	UL
LIN-4	H	H	M	UL	UL	UL	UL	UL	UL	UL
POA-1	H	M	L	UL						
POT-2	M	M	UL	M	UL	UL	UL	UL	UL	UL
TRE-5	UL	UL								
TRE-6	H	M	H	L						
TUC-1	UL	UL	L	M	UL	UL	UL	UL	UL	UL
TUC-2	M	M	M	H	H	H	M	M	H	UL
TUC-3	M	M	M	H	H	H	H	H	H	M
TUC-4	H	H	H	H	H	H	H	H	H	H
TUC-5	H	H	H	H	H	H	H	H	H	H
TUC-6	H	H	H	H	H	H	H	H	H	H
PHB-1	H	H	H	H	H	H	H	H	H	H

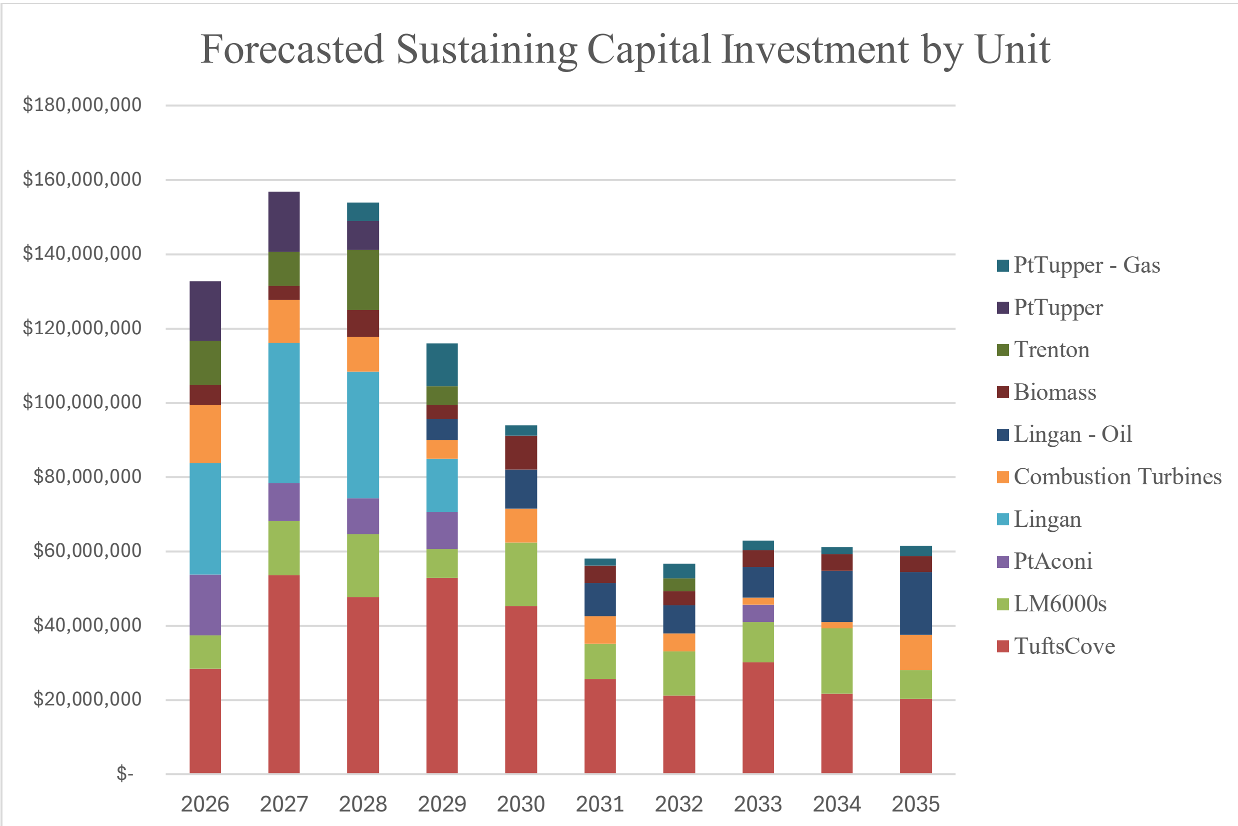
Figure 12 below provides the projected sustaining investments based on the anticipated utilization forecast in **Section 3.3.2.** Estimates of unit sustaining investment are forecast by applying the UF, related life consumption and known failure mechanisms. NS Power does not include unplanned failures in sustaining capital estimates. These estimates are evaluated at the asset class level; some asset class projections are prorated by the UF and others have additional overriding factors. For example, the use of many instrument and electrical systems is a function of calendar years, as they operate whether a unit is running or not. Investments for coal and ash systems are a direct function of capacity factor, as they typically have material volume-based failure mechanisms. In contrast, the UF is directly applicable to the investment associated with turbines, boilers and high energy piping. Major assets are regularly reassessed in terms of their condition and intended service as NS Power's operational data, utilization plan, asset health information, and forecasts are updated.

The overarching investment philosophy is to maintain unit reliability cost effectively while minimizing undepreciated capital. Mitigating risks by using less intensive investment strategies is a method executed throughout the thermal fleet. Major outage intervals are extended where

[23] H=High, M=Medium, L=Low, UL=Ultra Low

possible to reduce large investments in the thermal fleet.

Figure 12: Forecasted Sustaining Capital Investment by Unit



4.0 QUEUED SYSTEM IMPACT STUDIES

Figure 13 below provides the location and size of the generating facilities currently in the Combined Transmission & Distribution (T&D) Advanced Stage Interconnection Request Queue. Active transmission and distribution requests not appearing in the Combined T&D Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage, as they have not yet proceeded to the system impact study (SIS) stage of the Generator Interconnection Procedures (GIP) or Distribution Generator Interconnection Procedures (DGIP) by meeting the required GIP/DGIP milestones.

Figure 13: Advanced Stage Interconnection Queue as of June 19, 2025

Queue Order	T / D	IR#	Request Date	County	MW Summer	MW Winter	Interconnection Point	Type	In-Service Date	Status	Service Type
2	T	516	12/5/2014	Cumberland	1.26	1.26	37N	Tidal	12/31/2025	GIA Executed	NRIS
4	T	542	9/26/2016	Cumberland	3.78	3.78	37N	Tidal	6/30/2025	GIA Executed	NRIS
5	D	557	4/19/2017	Halifax	5.6	5.6	24H	Combined Heat Powerplant (CHP)		GIA on Hold	N/A
7	D	569	7/26/2019	Digby	0.6	0.6	509V-302	Tidal	9/30/2025	GIA Executed	N/A
9	T	574	8/27/2020	Hants	66.72	66.72	L-6051	Wind	9/30/2025	GIA Executed	NRIS
10	T	598	5/13/2021	Cumberland	2.52	2.52	37N	Tidal	6/30/2025	GIA Executed	NRIS
12	T	597	5/7/2021	Queens	36	36	50W	Wind	9/30/2025	GIA Executed	NRIS
16	T	664	7/26/2022	Lunenburg	50	50	99W	Battery	11/7/2025	GIA Executed	NRIS
17	T	662	7/26/2022	Halifax	50	50	132H	Battery	11/24/2025	GIA Executed	NRIS
18	T	670	8/5/2022	Colchester	94.4	94.4	L-7005	Wind	8/31/2027	GIA in Progress	NRIS
19	T	671	8/5/2022	Halifax	88.96	88.96	101V	Wind	3/31/2027	GIA in Progress	NRIS

Queue Order	T / D	IR#	Request Date	County	MW Summer	MW Winter	Interconnection Point	Type	In-Service Date	Status	Service Type
20	T	669	8/4/2022	Cumberland	99	99	L-6613	Wind	12/31/2025	GIA Executed	NRIS
21	T	668	8/3/2022	Antigonish	94.4	94.4	L-7003	Wind	10/31/2026	GIA Executed	NRIS
22	T	618	7/21/2021	Guysborough	130.2	130.2	L-7003	Wind	6/30/2026	GIA Executed	NRIS
23	T	673	8/9/2022	Hants	33.6	33.6	L-6054	Wind	10/15/2025	GIA Executed	NRIS
24	T	675	8/10/2022	Queens	112.5	112.5	50W	Wind	5/31/2028	GIA in Progress	NRIS
25	T	677	9/23/2022	Yarmouth	80	80	L-6024	Wind	11/15/2026	GIA Executed	NRIS
26	D	676	8/15/2022	Halifax	0.74	0.6475	103H-431	Solar	8/1/2025	GIA Executed	N/A
27	T	697	3/28/2023	Kings	50	50	43V	Battery	8/21/2026	SIS in Progress	NRIS
28	D	699	4/18/2023	Halifax	0.625	0.625	58H-431	Solar	8/30/2025	GIA Executed	N/A
31	T	686	1/23/2023	Cumberland	336	336	L-8001	Wind	5/31/2028	SIS in Progress	NRIS
34	T	739	9/20/2023	Queens	90	90	L-6025	Wind	12/31/2025	SIS in Progress	NRIS
35	T	742	10/13/2023	Guysborough	35	35	L-7003	Wind	6/30/2026	SIS in Progress	NRIS
36	D	716	8/3/2023	Halifax	0.24	0.24	139H-412	Solar	8/30/2025	GIA Executed	N/A
38	D	741	9/28/2023	Cumberland	5.072	4.072	3N-412	Solar	12/1/2025	GIA Executed	N/A
40	D	750	11/20/2023	Annapolis	0.25	0.25	70V-312	Solar	9/30/2025	SIS in Progress	N/A
41	D	752	1/1/2024	Hants	0.185	0.185	1N-402	Solar	12/31/2025	GIA in Progress	N/A
42	D	754	1/24/2024	Yarmouth	0.332	0.332	88W-314	Solar	9/30/2025	GIA in Progress	N/A
43	D	757	2/12/2024	Halifax	0.74	0.74	103H-431	Solar	6/30/2025	GIA in Progress	N/A
44	D	740	9/8/2023	Hants	0.25	0.25	20V-311	Solar	9/30/2025	GIA in Progress	N/A
45	D	778	4/22/2024	Guysborough	0.125	0.125	24C-443	Solar	06/15/2025	GIA in Progress	N/A

Queue Order	T / D	IR#	Request Date	County	MW Summer	MW Winter	Interconnection Point	Type	In-Service Date	Status	Service Type
47	D	795	7/24/2024	Kings	0.375	0.375	22V-322H	Solar	6/30/2025	GIA in Progress	N/A
48	D	788	5/27/2024	Halifax	0.555	0.555	58H-431	Solar	12/31/2025	GIA in Progress	N/A
49	D	768	4/2/2024	Halifax	0.435	0.435	101H-411	Solar	4/1/2025	SIS in Progress	N/A
50	D	777	4/12/2024	Guysborough	0.125	0.125	24C-442	Solar	4/1/2025	SIS in Progress	N/A
51	D	799	7/18/2024	Halifax	0.185	0.185	103H-433	Solar	6/30/2025	GIA in Progress	N/A
52	D	800	7/18/2024	Halifax	0.25	0.25	103H-433	Solar	6/30/2025	GIA in Progress	N/A
53	T	762	3/4/2024	Hants	16.8	16.8	L-6054	Wind	5/31/2026	SIS in Progress	NRIS
54	T	728	9/6/2023	Guysborough	120	120	L-7005	Wind	12/31/2027	SIS in Progress	NRIS/ERIS
55	T	824	12/16/2024	Guysborough	48	48	L-7005	Wind	12/15/2025	SIS in Progress	NRIS
56	D	837	1/30/2025	Hants	0.185	0.185	1N-402	Solar	3/30/2026	SIS in Progress	N/A

4.1 System Impact Studies (SIS)

As outlined in **Figure 13** above, a significant number of SIS are completed, and Standard Generation Interconnection and Operating Agreements (GIA) are executed or in progress. Of the SIS either in progress or completed, the majority study wind and solar generation facilities. With the associated increase in variable renewable inverter-based resources (IBR) on the system and the anticipated decrease in synchronous generation due to the coal-fired generation phase-out requirement by 2030, GIP SIS for Transmission Interconnections include Electromagnetic Transient (EMT) analysis in addition to Load Flow and Dynamic Analysis. The inclusion of EMT analysis allows for understanding the impacts of IBR interconnection and the requirements to maintain system reliability and stability. Every transmission SIS initiated for Study Group 32 and beyond has required or requires EMT analysis as part of their SIS to determine if additional equipment is needed to support the integration of the new generation resource.

4.2 OATT Transmission Service Queue

As of July 03, 2025 there are two requests in the Open Access Transmission Tariff (OATT) Transmission Queue as shown in **Figure 14.**

Figure 14: Requests in the OATT Transmission Queue as of July 03, 2025

Item	Project	Date & Time of Service Request	Project Type	Project Location	Requested In-Service Date	Project Size (MW)	Status
1	TSR 400	July 22, 2011	Point-to-point	NS-NB[24]	May 2019	330	System Upgrades and Project Completed
2	TSR 411	January 19, 2021	Point-to-point	NB-NS[24]	January 1, 2028	550	Facilities Study Completed

Information in **Figure 14** under Project Location reflects the non-confidential information provided in the customer's application. Details regarding the location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted are deemed confidential under Section 17.2 of the OATT[25] and not available to the public on the Open Access Same-Time Information System (OASIS). As such, there is limited further information the Company can include in this Report on a non-confidential basis.

[24] Indicates project as being located near provincial border.
[25] Nova Scotia Power Inc. Open Access Transmission Tariff As approved by the UARB May 31, 2005 and As Amended June 10, 2016. The OATT is available on NS Power's website at https://www.nspower.ca/docs/default-source/pdf-to-upload/revised-oatt-june-10-2016.pdf?sfvrsn=7d69fd73_0

5.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

5.1 Renewable Electricity Requirements

On July 9, 2021 the Province of Nova Scotia amended the Renewable Electricity Regulations to add a RES of 80 percent of energy sales beginning in 2030. NS Power was directed to meet this requirement, in part, through the acquisition of 1,100 GWh of new renewable energy from independent power producers. Please see **Section 3.2.4** above for details on the associated Rate Base Procurement program. For the years 2020-2024, the Company served 29 percent (2020), 30.4 percent (2021), 36 percent (2022), 42.5 percent (2023) and 40.5 percent (2024) of sales using qualifying renewable energy sources.

The near-term RES Compliance Forecast in **Figure 15** illustrates the full amount of RES-eligible energy forecast to be available to the Company for 2026, 2027 and 2030.

Figure 15: RES Compliance Forecast

RES Compliance Forecast			
	2026	**2027**	**2030**
Energy Requirements (GWh)			
NSR Including DSM effects	11,403	11,193	11,130
Losses	757	747	779
Sales	10,646	10,446	10,351
RES (%) Requirement	40%	40%	80%
RES Requirements (GWh)	**4,259**	**4,178**	**8,281**
Renewable Energy Sources (GWh)			
NS Power Wind	224	224	197
Post-2001 IPPs[26]	696	730	935
PH Biomass	198	199	250
COMFIT Wind Energy	481	481	415
COMFIT Non-Wind Energy	13	13	33
Eligible Pre-2001 IPPs	141	141	148
Eligible NS Power Legacy Hydro	925	925	998

[26] The increase in 2030 is a result of generation from 100MW of Community Solar installed by 2030.

RES Compliance Forecast			
REA Procurement (South Canoe/Sable)	310	326	242
New Wind - Rate Base Procurement, Green Choice, PHP, Minas Highlands	109	1,259	2,028
New Wind - Future Procurements	0	0	949
Renewable Import[27]	2,334	2,236	2,091
Forecast Renewable Energy (GWh)	**5,432**	**6,536**	**8,286**
Forecast Surplus or Deficit (GWh)	**1,174**	**2,358**	**6**
Forecast RES Percentage of Sales	**51%**	**63%**	**80%**

5.2 Environmental Regulatory Requirements

5.2.1 Nova Scotia Greenhouse Gas Emissions Regulations

The Nova Scotia Greenhouse Gas Emissions Regulations[28] specify emission caps for 2010-2030, as outlined in **Figure 16.** The net result is a hard cap reduction from 10.0 to 4.5 million tonnes over that 20-year period, which represents a 55 percent reduction in CO_2 release over 20 years. Carbon emissions in Nova Scotia from the production of electricity in 2030 are forecast to have decreased by 58 percent from 2005 levels of 10.64 million tonnes.

Figure 16: Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes (CO_2)
2010-2011	19.22
2012-2013	18.5
2013-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	5.5 (annual)

[27] Includes the Maritime Link Base Block, Supplemental Block, and Surplus Energy.
[28] *Greenhouse Gas Emissions Regulations* made under subsection 28(6) and Section 112 of the *Environment Act* S.N.S. 1994-95, c. 1, O.I.C 2009-341 (August 14, 2009), N.S. Reg. 260/2009 as amended to O.I.C. 2013-332 (September 10, 2013), N.S. Reg. 305/2013.

5.2.2 Nova Scotia Air Quality Regulations

The Nova Scotia Air Quality Regulations[29] specify emission caps for sulphur dioxide (SO2), nitrogen oxides (NOx), and mercury (Hg). These regulations were amended to extend from 2020 to 2030, effective January 1, 2015. The amended regulations replaced annual limits with multi-year caps for the emissions targets for SO2 and NOx.

The Province introduced amendments to the Air Quality Regulations respecting the SO2 cap for a three-year period from 2020 to 2022, effective January 21, 2020. The regulations also provide local annual maximums, as well as limits on individual coal units for SO2. The revised emissions requirements are shown below in **Figure 17.**

Figure 17: Emissions (SO_2, NOx, Hg)

<table>
<tr><th rowspan="2">Year(s)</th><th colspan="3">SO2 Tonnes</th><th colspan="2">Nox Tonnes</th><th>Mercury Kg</th></tr>
<tr><th>Unit Maximum</th><th>Annual</th><th>Cumulative</th><th>Annual</th><th>Cumulative</th><th>Annual</th></tr>
<tr><td>2021-2022</td><td>17,760</td><td>60,900</td><td>90,000</td><td>14,955</td><td rowspan="2">56,000</td><td>35</td></tr>
<tr><td>2023-2024</td><td>17,760</td><td>60,900</td><td>68,000</td><td>14,955</td><td>35</td></tr>
<tr><td>2025</td><td>13,720</td><td>45,000</td><td></td><td>11,500</td><td></td><td>35</td></tr>
<tr><td>2026</td><td>13,720</td><td>45,000</td><td rowspan="3">141,000</td><td rowspan="3">11,500</td><td rowspan="3">44,000</td><td rowspan="3">35</td></tr>
<tr><td>2027</td><td>13,720</td><td>40,000</td></tr>
<tr><td>2028-2029</td><td>13,720</td><td>28,000</td></tr>
<tr><td>2030</td><td>9,000</td><td>9,000</td><td></td><td>8,800</td><td></td><td>30</td></tr>
</table>

The annual SO2 limits from 2025 to 2027 are based on a Certificate of Variance issued by the Province which allows 45 kt in both 2025 and 2026 and 40 kt in 2027. The 2026-2029 cumulative limit is 141 kt and emissions in 2030 shall not exceed 9 kt in aggregate as per the Certificate of Variance. The Province directed NS Power to make up the 6.7 kg of Hg emissions overage in the 2023-2025 compliance period. NS Power made up 5.1 kg of excess mercury emissions in 2023 and the remaining 1.6 kg of excess mercury emissions in 2024.

[29] *Air Quality Regulations* made under Sections 25 and 112 of the Environment Act S.N.S. 1994-95, c. 1 O.I.C. 2005-87 (February 25, 2005, effective March 1, 2005), N.S. Reg. 28/2005 as amended to O.I.C. 2020-016 (effective January 21, 2020), N.S. Reg. 8/2020.

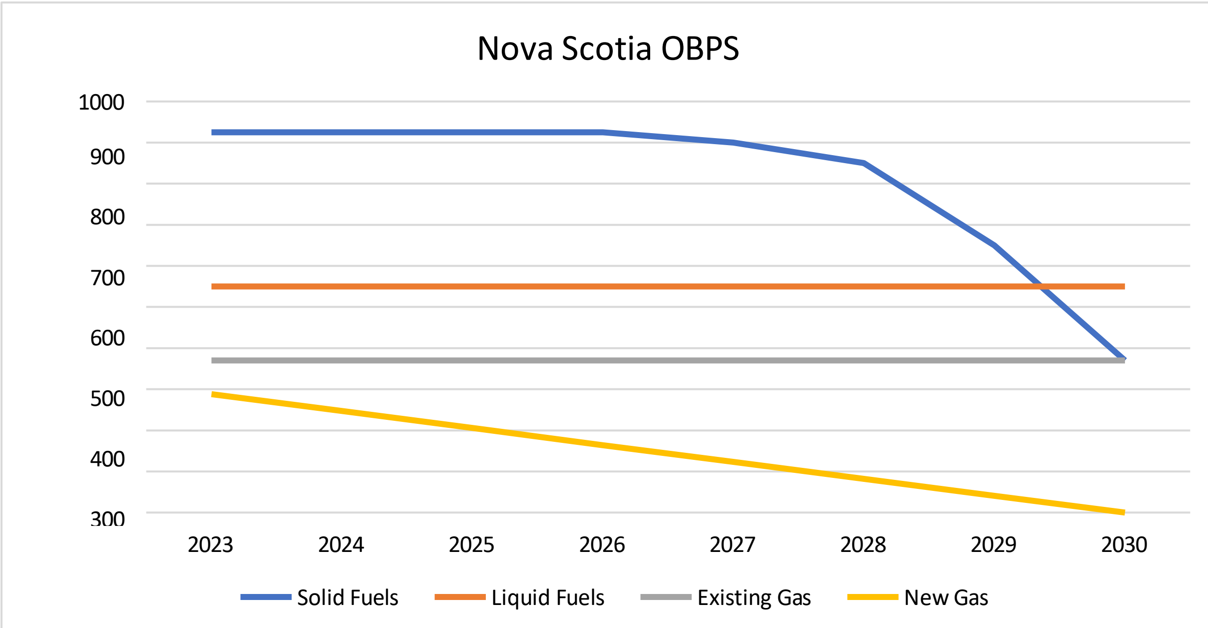
SO2 reductions are being addressed mainly by reduced thermal generation and changes to fuel blends. NOx reductions are being addressed through reductions in thermal generation and the previous installation of Low-NOx Combustion Firing Systems. Mercury reductions are being accomplished through reduced thermal generation, changed fuel blends, and the use of Powder Activated Carbon (PAC) systems. NS Power offered a mercury recovery program from 2015 to the end of January 2020. The program involved recycling light bulbs or other mercury-containing consumer products, which reduced the amount of mercury going into the environment through landfills. NS Power generated 193.5kg of mercury credits that were approved by Nova Scotia Environment and Climate Change (ECC) to compensate for deferred mercury emissions by 2020, and a limited number of credits were approved by ECC (30 kg in 2020, 10 kg per year for subsequent years) for compliance from 2020 to 2029.

5.2.3 Nova Scotia Output-Based Pricing System

In October 2022, the Province updated the Environment Act, moving from the previous cap-and-trade system to a provincial output-based pricing system (Nova Scotia OBPS, referred to as the "NS OBPS") starting January 1, 2023 (the regulation was published December 29, 2023 retroactive to January 1, 2023). The NS OBPS sets emissions intensity limits for various fuels consumed in electricity generating facilities. Facilities covered under the NS OBPS program include solid fuels, liquid and gaseous fuels, and the emissions limit is calculated using emissions-intensity performance standards for electricity generation by fuel type. Facilities that emit more than the applicable emission intensity limits must provide compensation for the excess emissions, which are priced according to the federal carbon price. The performance standards for the NS OBPS by fuel type are shown in **Figure 18**.

[30] Nova Scotia Legislature – Bill No.208: c046.pdf (nslegislature.ca)

Figure 18: NS OBPS Emission Intensity Standards



5.2.4 Environmental Goals and Climate Change Reduction Act

The Province introduced the Environmental Goals and Climate Change Reduction Act (EGCCRA) on October 27, 2021.[31] The EGCCRA includes the 80 percent RES 2030 goal in addition to the requirement to phase out coal-fired electricity generation in the Province by 2030. It also includes provincial GHG reduction targets of 53 percent below 2005 levels by 2030, Net Zero by 2050 (discussed further in **Section 5.3**), and a zero-emission vehicle mandate that will require 30 percent of new vehicle sales of all light duty and personal vehicles in the Province by 2030 to be zero-emission vehicles. The Government of Canada also has federal targets of 100 percent zero-emission new vehicles by 2035, with interim targets of 20 percent by 2026, and 60 percent by 2030.

[31] Environmental Goals and Climate Change Reduction Act, S.N.S. 2021, c. 20, s. 1.

5.3 Clean Electricity Regulations

On December 18, 2024, the Clean Electricity Regulations (CER) were published in Canada Gazette 2 (CG2) after a period of stakeholder engagement with industry led by Environment and Climate Change Canada (ECCC). The intent of the CER is to reduce emitting generation starting in 2035 to enable a net zero electricity system in Canada by 2050. While NS Power is reducing the contributions from emitting resources to meet overall RES requirements, the use of emitting resources as peaking facilities (use during periods of peak system demand and/or when renewable resources are in low supply) plays a critical role in the integration of variable renewable generation (wind, solar) and to support system reliability. The CER recognizes this important role and establishes the following components of the regulation to enable this:

- Allowable emissions limit (AEL): each thermal generating unit can emit up to the allowable emissions limit of 65 tonnes/GWh of CO_2 on an annual basis. This emissions limit is applied to the installed capacity of the unit (e.g. a 100 MW) to calculate the total CO_2 emissions each unit can emit in the given year. The AEL will be in place until the end of 2049 and drops to zero in 2050.

- Offsets: each generating unit can purchase offsets, in addition to the allowable emissions limit, up to 35 tonnes/GWh. Similar to the AEL, this is applied to the installed capacity of the unit to calculate the total offsets NSP can purchase to offset emissions for that specific unit. The offset limit will be in place until the end of 2049 and will increase to 45 tonnes/GWh in 2050.

- Pooling: for all thermal units in operation by the end of 2029, Nova Scotia can pool the allowable emissions. This allows the thermal units within the pool to be dispatched in the manner that is optimal from a cost and emissions perspective provided the actual total CO_2 emissions does not exceed the combined total CO_2 emissions for all units in the pool. For example, if two 100MW units have a combined AEL of 114kT in a given year, the less costly/lower emitting unit can be operated more than the higher cost/higher emitting unit as long as the total emissions for both units do not exceed 114kT. This provides operators with the flexibility to optimize the dispatch of these units to minimize system costs while also minimizing system emissions.

The AEL and offsets apply to all existing and new emitting resources, as defined in the CER, for the NS Power resource mix in 2035 and beyond (natural gas, heavy fuel oil, diesel). The pooling provisions will apply to all existing and new emitting resources, as defined in the CER, in operation by the end of 2029.

The final CER are generally aligned with how they were considered in the 2023 Evergreen IRP, which determined the current long-term resource plan.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

Operating Reserves are resources which can be called upon by system operators on short notice to respond to the unplanned loss of generation or imports or unanticipated changes in load. These assets are essential to the reliability of the power system.

As a member of the Maritimes Area of NPCC, NS Power meets the operating reserve requirements as outlined in NPCC Regional Reliability Reference Directory #5, Reserve. These criteria are reviewed and adjusted periodically by NPCC and subject to approval by the NSEB. The criteria require that:

> Each Balancing Authority shall have ten-minute reserve available that is at least equal to its first contingency loss.[32]
>
> and
>
> Each Balancing Authority shall have thirty-minute reserve available that is at least equal to one-half its second contingency loss.[33]

NS Power's 10-minute reserve requirement is equal to the Most Severe Single Contingency (MSSC) within the Nova Scotia Balancing Area. This 10-minute reserve requirement cannot be less than 168MW because this is the fixed value of reserve assistance that NS Power and NB Power have agreed to provide one another for contingencies with the Maritimes Area. This 168 MW of 10-minute reserve is comprised of 32MW (spinning) and 136 MW (non-spinning). NS Power is also required to carry a minimum of 50MW of 30-minute reserve. The reserve requirements for NS are outlined in the Interim Operating Agreement between NS Power and NB Power. Additional regulating reserve is maintained to manage the variability of customer load and generation.

[32] https://www.npcc.org/standards/regional-criteria

[33] https://www.npcc.org/standards/regional-criteria

6.2 Planning Reserve Criteria

The Planning Reserve Margin (PRM) is intended to maintain sufficient resources to reliably serve firm customers. Unit forced outages, higher than forecast demand, and lower than forecast variable renewable generation are all conditions that could individually or collectively contribute to a shortfall of dispatchable capacity resources to meet customer demand.

NS Power is required to comply with the NPCC reliability criteria that have been approved by the NSEB. These criteria are outlined in *NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System* which states:

> 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. [This evaluation shall] 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.[34]

The PRM is a long-term planning assumption that is typically updated as part of an IRP process. NS Power studied the appropriate calculation of its PRM as part of the 2020 IRP[35] which confirmed that a 20 percent PRM target was appropriate for long-term planning.

The PRM provides a basis for the minimum required firm generation NS Power must plan to maintain to comply with NPCC reliability criteria; it does not represent the optimal or maximum required capacity to serve other system requirements. The optimal capacity requirement is determined through a long-term planning exercise such as the Evergreen IRP, as discussed in **Section 3.2.1.**

[34] https://www.npcc.org/standards/regional-criteria
[35] Nova Scotia Power IRP Final Report (M08929), November 27, 2020, page 40.

6.3 Capacity Contribution of Renewable Resources in Nova Scotia

Due to their variability, the capacity contribution from a variable renewable resource counted towards the PRM must be evaluated. The ELCC, or “capacity value”, of a resource represents the anticipated contribution from renewable resources during periods when the grid is most likely to experience capacity shortfalls and, as a result, what percentage of its nameplate capacity can be counted on as firm for system planning. Loss of Load Expectation (LOLE) studies are the industry standard used to calculate the ELCC or capacity value of intermittent renewable resources.

In a letter dated October 5, 2018[36] the NSEB directed NS Power to complete certain pre-IRP analyses by July 31, 2019. One of the pre-IRP deliverables directed by the NSEB was a Capacity Study to calculate the ELCC of wind and other renewable energy generators, both for the existing wind resources as well as potential new resources. The study was undertaken by Energy+Environmental Economics (E3)[37] on behalf of NS Power and the results determined the average ELCC of the wind installed on the NS Power system at that time to be 19 percent. The declining marginal ELCC value of adding new wind to the NS Power system was determined to be 11 to 9 percent at current levels and decreasing as more wind is added. For the purposes of this Report, NS Power has used the 18 percent capacity value of existing wind to account for the wind farm serving wholesale market participants under the Back-up / Top-up (BUTU) Tariff. **Figure 19** below summarizes the ELCC values used for new wind additions.

[36] UARB Decision Letter, Generation Utilization and Optimization, M08059, October 5, 2018.
[37] Integrated Resource Planning and Generation Utilization and Optimization, M08929, (P-884). Energy+Environmental Economics, Planning Reserve Margin and Capacity Value Study, July 2019, Attachment 18 to NS Power’s Pre-IRP Final Report at https://irp.nspower.ca/documents/pre-irp-deliverables/

Figure 19: Marginal ELCC Percentage for New Wind Additions

Winter Period	Annual Wind Capacity Added (MW)	Cumulative Capacity of Wind (MW)	Marginal ELCC% Applied to New Wind Capacity	Firm Capacity Contribution from New Wind (MW)
Pre- 2025		611		
2025/2026	128	645	10%	12.8
2026/2027	449	1188	10%	44.9
2027/2028	59	1246	10%	5.9
2028/2029	262	1508	8%	20.9
2029/2030	350	1858	8%	28
2030/2031	300	2158	8%	24
2031/2032	200	2358	6%	12
2032/2033	200	2558	6%	12
2033/2034	200	2758	6%	12
2034/2035	150	2908	6%	9

For hydro sites an ELCC of 95 percent is applied with the exception of the Mersey Hydro system. Refer to **Section 3.1.2** for further details about Mersey. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0 percent.

In a letter dated May 23, 2024, in response to NS Powers 2023 Evergreen IRP Action Plan and Roadmap update, the NSEB stated:

> As noted by Synapse in its August 2023 comments, the battery energy storage ELCC profile is a critical input value to the modeling. This needs to be carefully re-examined in conjunction with an updated portfolio ELCC analysis, which considers the interactive effect of all four clean resources (i.e., wind, solar PV, battery energy storage, and demand response or peak load mitigation during winter peak periods). The Board sees value in further study to evaluate the incremental diversity benefit available from increased interaction among renewable resources.[38]

NS Power affirmed its support for updating the ELCC study in the 2024 10-Year System Outlook

[38] NSEB Decision Letter, re: M11307 - Evergreen IRP Updated Action Plan and Roadmap – 2023, May 23, 2024, p.5.

report (M11764), where it states on page 48:

> NS Power supports updating the capacity study prior to the next IRP analysis, with the focus of the update being an examination of the interactive effect of the identified clean resources (wind, solar, battery energy storage, and demand response).[39]

NSEB IR-2 on the 2024 10-Year System Outlook report asked for an update on NS Power's progress on this recommendation. NS Power's response stated:

> NS Power has not started a new capacity value study, but as stated in the 2024 10-Year System Outlook report on page 48, NS Power supports updating the most recent capacity value study prior to the next IRP analysis, with the focus of the update being an examination of the interactive effect of the identified clean resources (wind, solar, battery energy storage, and demand response). As a starting point for this work, NS Power will develop a draft scope of work and project schedule to be circulated to IRP stakeholders for comment by the end of the year. This will allow stakeholders the ability to comment on the statement of work at the initial stages of development.[40]

In accordance with this commitment on February 6, 2025 NS Power issued a draft scope of work for stakeholders to review and requested feedback to be provided by February 21, 2025. NS Power received feedback from the Department of Energy, the Consumer Advocate, the Small Business Advocate, the Industrial Group, Efficiency One, Energy Storage Canada and Solar Nova Scotia. NS Power is in the process of revising the scope and responding to stakeholder feedback.

6.4 Load and Resources Review

The 10-year load and resources outlook in **Figure 20** is based on the capacity changes and DSM forecast from **Figure 6** and provides details regarding NS Power's required minimum forecast PRM equal to 20 percent of the firm peak load. The capacity additions and retirements are in alignment with the CE1-E1-R2 Evergreen IRP scenario and the Province of Nova Scotia's 2030

[39] NS Power 2024 10-Year System Outlook Report (M11764), June 27, 2024, p.48.
[40] NSEB IR-2, NS Power 2024 10-Year System Outlook Report (M11764), September 19, 2024, p.1.

Clean Power Plan. Modifications have been made for any projects with known capacity or in-service date updates.

In 2024, NS Power decided to continue to hold Lingan 2 available in cold reserve, recallable to service as needed in order to mitigate challenges with near-term resource adequacy. The 2025 load forecast shows firm peak load continuing to increase to 2030 and beyond. Therefore, NS Power will continue this strategy with Lingan 2 and plan the unit retirement following the addition of new fast acting generation resources procured by the NSIESO, and reliable operation of these assets is established.

Figure 20: NS Power 10-Year Load and Resources Outlook

Load and Resources Outlook for NS Power - Winter 2025/2026 to 2034/2035 (All values in MW except as noted)											
		2025/ 2026	**2026/ 2027**	**2027/ 2028**	**2028/ 2029**	**2029/ 2030**	**2030/ 2031**	**2031/ 2032**	**2032/ 2033**	**2033/ 2034**	**2034/ 2035**
A	Firm Peak including effects of DSM & DR	**2,263**	**2,268**	**2,274**	**2,285**	**2,303**	**2,332**	**2,364**	**2,402**	**2,449**	**2,503**
B	Required Reserve (A x 20%)	453	454	455	457	461	466	473	480	490	501
C	Required Capacity (A + B)	2,716	2,722	2,729	2,742	2,764	2,798	2,837	2,882	2,939	3,004
D	Existing Resources (NS Power and IPPs)	2,594	2,594	2,594	2,594	2,594	2,594	2,594	2,594	2,594	2,594
E	Existing Resources (Wholesale Market Resources) [3]	4	4	4	4	4	4	4	4	4	4
F	Total Existing Resources (D + E)	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598
G	Firm Resource Additions:										
H	Hydro	-101	101								
I	New Wind - Rate Base Procurement	12.8	17.8								
J	New Wind - Green Choice				20.9						
K	New Wind Projects - PHP & Minas Highlands		18.1								
L	New Wind - Future Procurement Rounds					28.0	24.0	12.0	12.0	12.0	9.0
M	New Wind - Renewable to Retail		9.0	5.9							
N	Additions - Coal to Gas Conversion				150						

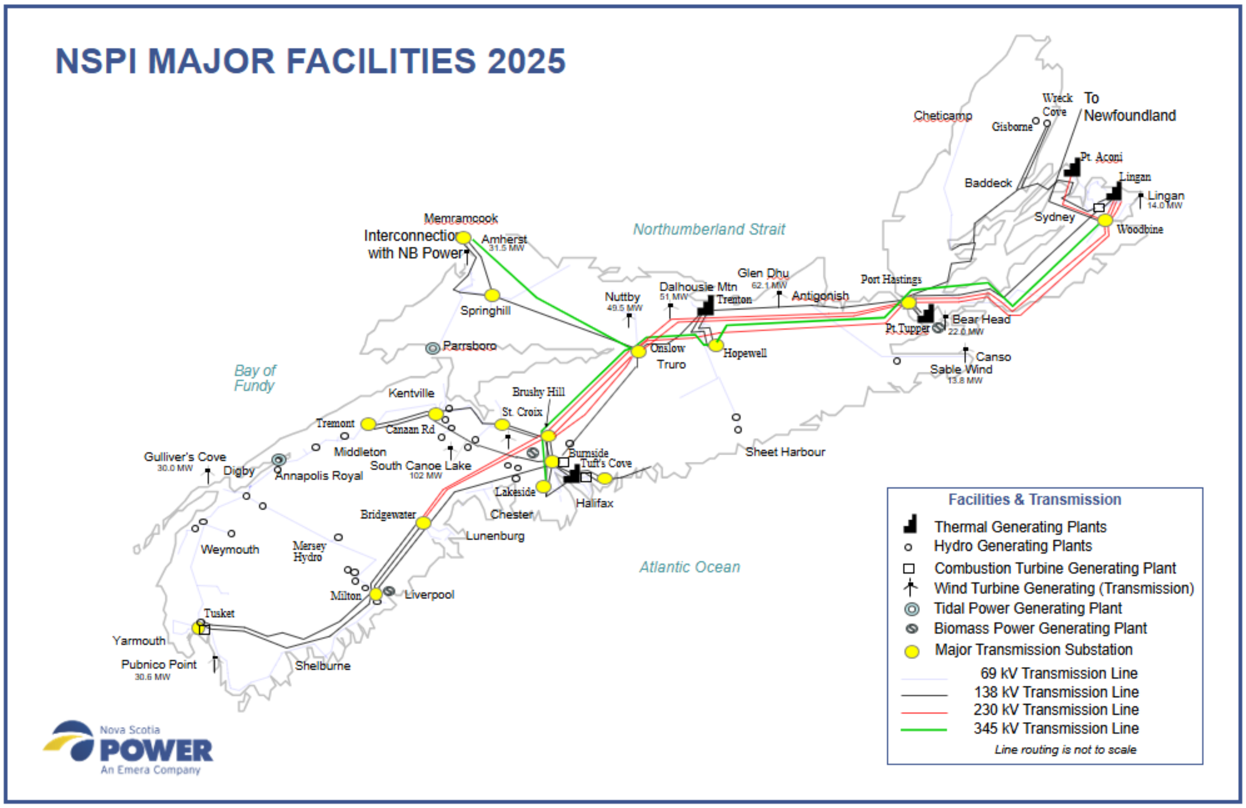
Load and Resources Outlook for NS Power - Winter 2025/2026 to 2034/2035 (All values in MW except as noted)											
		2025/ 2026	**2026/ 2027**	**2027/ 2028**	**2028/ 2029**	**2029/ 2030**	**2030/ 2031**	**2031/ 2032**	**2032/ 2033**	**2033/ 2034**	**2034/ 2035**
O	Additions - New Gas CTs			300		300					
P	Additions - Battery	72	24	49		36					
Q	Additions - Coal to HFO Operation					459					
R	Diversity Credit		3	3	3	3					
S	Retirements			-298	-150	-781					
T	Total Annual Firm Additions (Sum of rows G thru S)	-16	173	59	24	45	24	12	12	12	9
U	Total Cumulative Firm Additions (T + U of the previous year)	-16	156	216	240	285	309	321	333	345	354
V	Total Firm Capacity (F + U)	2,582	2,755	2,814	2,838	2,883	2,907	2,919	2,931	2,943	2,952
	+ Surplus / - Deficit (V - C)	-134	33	85	96	119	109	82	49	4	-52
	Reserve Margin % [(V - A)/A]	14%	21%	24%	24%	25%	25%	23%	22%	20%	18%

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has approximately 5,200 km of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels. The configuration of the NS Power transmission system and major facilities is shown in **Figure 21**.

Figure 21: NS Power Major Facilities in Service



The 345 kV transmission system is approximately 468 km in length and comprises 372 km of steel tower lines and 96 km of wood pole lines.

The 230 kV transmission system is approximately 1,271 km in length and comprises 47 km of steel/laminated structures and 1,224 km of wood pole lines. The 138 kV transmission system is approximately 1,871 km in length and comprises 303 km of steel structures and 1,568 km of wood pole lines. The 69 kV transmission system is approximately 1,560 km in length and comprises 12 km of steel/concrete structures and 1,548 km of wood pole lines.

Nova Scotia is interconnected with the New Brunswick electric system through one 345 kV and two 138 kV lines providing up to 505 MW of transfer capability to New Brunswick and between 0 and 300 MW of transfer capability from New Brunswick, depending on system conditions. As the New Brunswick system is interconnected with the province of Quebec and the state of Maine, Nova Scotia is integrated into the NPCC bulk power system with New Brunswick as part of the Maritime Area.

Nova Scotia is also interconnected with Newfoundland via a 500 MW, +/-200 kV DC link referred to as the Maritime Link. The Maritime Link is owned and operated by NSP Maritime Link Inc., a wholly owned subsidiary of Emera Newfoundland & Labrador.

7.2 Transmission Design Criteria

Consistent with good utility practice, NS Power utilizes a set of deterministic criteria for its interconnected transmission system that combines protection performance specifications with system dynamics and steady-state performance requirements. The approach used has involved the subdivision of the transmission system into various classifications, each of which is governed by the NS Power System Design Criteria. The criteria require the overall adequacy and security of the interconnected power system to be maintained following a fault on and disconnection of any single system component.

7.2.1 Bulk Power System (BPS)

The NS Power bulk transmission system is planned, designed and operated in accordance with NERC Standards and NPCC criteria. NS Power is a member of the NPCC; therefore, those portions of NS Power’s bulk transmission network where single contingencies can potentially adversely affect the interconnected NPCC system are designed and operated in accordance with the NPCC Regional Reliability Directory 1: Design and Operation of the Bulk Power System and are defined as Bulk Power System (BPS).

7.2.2 Bulk Electric System (BES)

The NERC Bulk Electricity System (BES) definition encompasses any transmission system element at or above 100 kV with prescriptive inclusions and exclusions that further define BES. System Elements that are identified as BES elements are required to comply with all relevant NERC reliability standards.

NS Power has adopted the NERC definition of the BES and an NS Exception Procedure for elements of the NS transmission system that are operated at 100 kV or higher for which contingency testing has demonstrated no significant adverse impacts outside the local area. The NS Exception Procedure is used in conjunction with the NERC BES definition to determine the accepted NS BES elements and is equivalent to Appendix 5C of the NERC Rules of Procedure.

The BES Definition and NS Exception Procedure were approved by NSEB Order dated April 6, 2017. Under the BES definition and NS Exception Procedure approved by the NSEB, elements classified as NS BES elements are required to adhere to all relevant NERC standards that have been approved by the NSEB for use in Nova Scotia.

7.2.3 2024 Bulk Electric System Exception Requests

Since the filing of the 2024 10-Year System Outlook report, no new BES Exception Requests have been received.

7.2.4 Remedial Action Schemes (RAS)

NS Power makes use of Remedial Action Schemes (RAS) in conjunction with the Supervisory Control and Data Acquisition (SCADA) system to enhance the utilization of transmission assets. These systems act to maintain system stability and remove equipment overloads, post-contingency, by rejecting generation and/or shedding load. The NS Power system has several transmission corridors that are regularly operated at limits without incident due to these RAS. RAS are also referred to as Special Protection Systems (SPS) in NERC documentation. Both terms are valid.

NS Power expects to modify the existing RAS to accommodate the anticipated renewable energy resource additions to the system expected by 2030. Each modification will require NPCC approval.

7.2.5 NPCC Directory 1 Review

The D1 Working Group under the NPCC Task Forces on Coordination of Planning (TFCP) and Coordination of Operation (TFCO) has completed its review of the NPCC Directory 1 Document: Design and Operation of the Bulk Power System. The revised Directory 1 document was published on July 2, 2024. Directory 1 provides a "design-based approach" to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the contingencies referenced.

7.2.6 NPCC Directory 7 Review

A Working Group under the NPCC TFCP and TFCO is nearing the end of its review of the NPCC Directory 7 Document: Remedial Action Schemes. Membership was solicited from the NPCC Task Forces on Coordination of Planning, and Coordination of Operation and other interested representatives of NPCC Member Companies.

At present, Directory 7 establishes the design criteria and review process for a RAS. The purpose of the NPCC process is to review the classification and design of a RAS according to its power system impact. NS Power has representation from System Planning on the Directory 7 Working Group that is performing the review. The Directory 7 Working Group now anticipates the review will be complete in Q3 2025.

7.3 Transmission Life Extension

NS Power has a comprehensive maintenance program in place for the transmission system, which is focused on maintaining reliability and extending the useful life of transmission assets. The program is centered on detailed transmission asset inspections and associated prioritization of asset replacement (i.e. conductor line, poles, steel structures, cross-arms, guywires, and hardware replacement).

Transmission line inspections consist of the following actions:

- Visual inspection of every line once per year via helicopter, or via ground patrol in locations not practical for helicopter patrols.

- Foot patrol of each non-BPS line on a three-year cycle. Where a LiDAR survey is requested for a non-BPS line, the survey replaces the foot patrol in that year.

- For BPS lines, LiDAR surveys every two years out of three, with a foot patrol scheduled for the third year.

These inspections identify asset deficiencies or damage and confirm the height above ground level of the conductor span while recording ambient temperature. This enables the NSPSO to confirm that the rating of each line is appropriate.

7.4 New Large-Load Customer Interconnection Requests

NS Power continued to receive large-load requests in 2024 with respect to proposed commercial, mining, and government projects. In particular, two projects associated with Hydrogen production development continue to proceed through the load interconnection process while also establishing a suitable supply of renewable electricity supply via a combination of wind and solar resources.

Since June 30, 2024, forty nine (49) Distribution Preliminary Assessments were performed in the range of 1 - 20 MW, leading to the completion of eight (8) formal Load Impact Studies on the distribution system. In some instances, Preliminary Assessments determined that a Load Impact Study was not required. Not all of these assessments translate into near-term load, as some projects have multi year construction or are not completed. In addition, one (1) formal Load Impact Study (LIS) on the transmission system was completed; two (2) transmission LIS are in progress; one (1) transmission Facilities Studies was completed, one (1) transmission Facilities Study is in progress, and one (1) Interconnection Agreement was completed. Transmission Projects range from 3 MW to 1000 MW.

7.5 Reliability Intertie

On April 10, 2025, Wasoqonatl Transmission Incorporated (WTI) filed the NS-NB Reliability Intertie Project Application[41] to build the Reliability Intertie, a second 345 kV AC transmission line between the NS Power system and the NB Power system. The Reliability Intertie will support NS Power's ability to continue to reliably integrate, and maximize the value of, increasing amounts of renewable generation, supporting provincial mandates for achievement of 80 percent renewable energy and the phase out of coal fired electricity generation by 2030. WTI anticipates the Reliability Intertie being put into service in Q4 of 2028.

[41] M12217, NS-NB Reliability Intertie Project Application, Wasoqonatl Transmission Incorporated, April 10, 2025.

7.6 Western Valley Transmission System – Phase II Study

The Western Valley transmission study was initiated to determine the system upgrades needed to address transmission line capacity, clearance, and age issues in the Western Valley over a 15-year transmission planning horizon. In particular, the following 69 kV lines were targeted:

- L-5531 (13V-Gulch to 15V-Sissiboo)
- L-5532 (13V-Gulch to 3W-Big Falls)
- L-5535 (15V-Sissiboo to 9W-Tusket)
- L-5541 (3W-Big Falls to 50W-Milton)

The scope of the study was subsequently expanded in 2022 to also include the impacts of electrification on the Western Valley and Western regions. However, study work was paused due to an influx of Feasibility Studies and System Impact Studies related to the Rate Base Procurement (RBP) and the Green Choice Procurement (GCP); these studies include the addition of IPP renewable generation projects in the Valley and Western regions.

Work on the Western study evolved in 2024 following completion of these interconnection studies. Study cases were updated to reflect forecasted load and system upgrades associated with committed wind generation in the Valley and Western portions of the province in accordance with the Combined T/D Advanced Stage Interconnection Request Queue, and draft recommendations were developed in Q2 of 2025 and are detailed in **Section 8.3**.

7.7 Hydrogen Load Impact Studies

There are currently two Hydrogen facilities that are following the Bulk Power Interconnection Procedures to interconnect their plants to the Nova Scotia transmission system, with a combined total load of approximately 1225 MW. To date, these load customers have also submitted generation interconnection requests for transmission system connections of 1235 MW of renewable generation (wind) and have identified the need for 350MW of behind the meter connections (solar and BESS).

7.8 EMT Studies to Support Wind Integration

NS Power, in collaboration with Manitoba Hydro International (MHI), is currently completing the second stage studies on the Large Scale Integration of Inverter Based Resources in Nova Scotia study. Studies indicate that NS Power can incorporate inverter-based resources (IBRs), such as wind, limited only by the load to be served and the best economic dispatch to meet target metrics for renewables.

EMT Study Updates:

- The NS Power Transmission System Interconnection Requirements (TSIR) was revised on November 25, 2024 to incorporate the findings to date to better define minimum interconnection requirements for wind, solar and BESS.

- Large scale grid studies are ongoing to determine operating and commissioning guidelines for a grid with high IBR dispatch hours.

- A review of Protection and Control practices for operation in a high IBR grid is ongoing. Recommendations and findings will be included in the report on Stage 2 studies for the Large Scale integration of IBR in Nova Scotia.

- Stage 2 studies for the Large Scale Integration of Inverter Based Resources in Nova Scotia will be integrated into a report that is expected to be published in Q4 2025.

7.9 System Inertia and Strength

Conventional synchronous machine-based power generation supplies both active power and reactive power, resulting in high Short Circuit MVA (SCMVA) levels in most areas. SCMVA is a measure of the ability of a system to withstand voltage events. Synchronous machines also resist changes in frequency as they are large machines with a heavy rotating mass that continues to rotate at close to 60Hz for up to a few seconds after a system interruption and act to resist the frequency change in the grid due to the changing conditions. This is known as Synchronous Inertial Response (SIR).

Large-scale penetration of renewable inverter-based generation will displace conventional synchronous machine-based power generation. This has the potential to lower the overall system inertia and will result in lower short circuit levels at the Point of Interconnection (POI) of renewable resources.

7.9.1 System Inertia

Inverter-based resources, such as wind, solar and batteries, do not inherently support system frequency swings as they do not provide the natural SIR that the traditional synchronous machines provide.

If the load and generation balance is not maintained, the system frequency will fluctuate and equipment may trip, or electrical power swings may occur. The Rate of Change of Frequency (RoCoF) can also impact system performance. A high RoCoF can make it difficult for equipment in the network to stay connected or operate stably. If frequency deviations can be well damped and RoCoF managed to allow the system load and generation to remain online, system stability will be maintained.

As NS Power retires or decreases dispatch hours of traditional synchronous plants, sufficient resources to manage frequency deviation and limit RoCoF will be required online. NS Power continues to progress studies in this area and updated findings will be published in Q4 2025 in a report on Stage 2 studies for the Large Scale Integration of Inverter Based Resources in Nova Scotia.

7.9.2 System Strength

System Strength is a metric used to determine the ability of IBR facilities to stay online during grid disturbances. System Strength is typically measured as the SCMVA contribution from synchronous machines measured at the point of interconnection of the IBR facility.

Each new generation or BESS facility is required to stay online during expected operating conditions over the life of the project. The general rule to calculate this ability is Short Circuit Ratio (SCR). SCR is the ratio of the SCMVA at the POI divided by the plant maximum MW output. The plant output in this calculation is the sum of all plants in close proximity to each other which reduces the SCR as IBR increase in the province. To meet the 2030 renewable targets, NS Power will require wind, solar and/or BESS in all areas of the province resulting in dropping SCRs even as SCMVA remains at or above today's minimums. Each new facility is required to design and operate their facility in high IBR conditions with an SCR expected to decrease over time.

The TSIR were revised to provide technology specific requirements for system strength support required to allow a facility to connect, maintain adequate performance, and not cause an adverse impact on existing customers.

New facilities are required to meet updated requirements as follows:

- Synchronous machines
  - **7.5.4.** Inertia Constant
- Asynchronous machines
  - **7.6.11.** Inertia Equivalent Response – Grid following IBR
  - **7.6.12.** Inertia Equivalent Response – Grid Forming IBR

For existing IBR facilities, such as the HVDC link and the SVC, it is the responsibility of NS Power will maintain sufficient system strength to ensure their reliable operation.

8.0 TRANSMISSION DEVELOPMENT

The transmission plan presented in this document provides a summary of the planned reinforcement of the NS Power transmission system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria and other standards. NS Power has sought to upgrade existing transmission lines and utilize existing plant capacity, system configurations, and existing rights-of-way and substation sites where economic.

Major projects included in the plan have been included based on a preliminary assessment of need. The projects will be subject to further technical studies, internal approval at NS Power, and approval by the NSEB. Projects listed in this plan may change because of final technical studies, changes in the load forecast, changes in customer requirements or other matters determined by NS Power, NPCC/NERC Reliability Standards, or the NSEB. Items described below are current as of the date of this report.

8.1 Impact of Proposed Load Facilities

There were several system upgrades required to serve load facilities greater than 1 MW that were proposed in 2020 and 2021. These projects precipitated the need for the following system upgrades:

1. Construction of new 15/20/25 MVA, 138 kV-25 kV substation at 101W-Bowater. This substation is anticipated to enter service in Q3 2025.

2. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton. Construction on the new 98N-Stellarton substation will begin in Q3 2025 with an expected completion date of Q4 2026.

3. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow in Q4

2026.

4. Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Susie Lake Crescent in 2026.

5. Installation of a new 10 MVA, 69-25 kV portable dead-front transformer on-line L-5510 required to provide a 25 kV supply to a new mine site. The in-service date is contingent on the customer initiating the project which has been deferred.

8.2 129H-Kearney Lake Relocation

Detailed inspection of the original proposed land parcels for relocation of 129H revealed that site development costs would be much higher than expected to grade the property and provide a suitable access route into the site for a mobile transformer unit. As part of M10897 land transfer agreement approved by the NSEB, NS Power is proceeding with the design option that involves surrendering a small portion of the existing L-6038 ROW and modifying the transmission termination points and approach of transmission lines L-6038 and L-5004 to 129H. The detailed engineering design to accommodate for the substation expansion of 129H as well as the design to accommodate for the new approach of L-6038 and L-5004 has been completed and work to modify lines L-6038 and L-5004 is currently underway.

8.3 Transmission Development Plans

Transmission development plans are summarized below. As noted, these projects are subject to change.

2025

- Completion of new 15/20/25 MVA, 138 kV-25 kV substation at 101W-Bowater.
- Replace Maitland Bridge transformer 76V-T1.

- Construct new 138 kV–25 kV, 25/33/42 MVA Mt. Uniacke Substation (143H) complete with three 25 kV distribution feeders.
- Construct new 138 kV–25 kV, 25/33/42 MVA 98N-Stellarton Substation complete with three 25 kV distribution feeders.
- Replace existing 50/66.7/83.3 MVA 138 kV-69 kV Tufts Cove auto-transformer with a similarly rated unit.
- Replace Victoria General Hospital transformer 10H-T41.
- Transmission Right-of-Way Widening (138kV & 230kV) to reduce the risk of edge and off right-of-way tree fall-in contacts.
- Purchase replacement spare 69-12.5kV, 7.5/10/12.5MVA transformer.

2026

- Re-align L-6038 transmission structures on approach to the 129H-Kearney Lake Substation.
- 129H-Kearney Lake Substation rebuild.
- Construct new 25/33/42 MVA 138 kV-25 kV Susie Lake Substation complete with four 25 kV distribution feeders.
- Construct new 15/20/25 MVA 138 kV-25 kV 113W-Cookeville (Bridgewater) Substation complete with two 25 kV distribution feeders.
- Install a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow.
- Replace 83V-Wolfville Ridge transformer 83V-T51 with a 138/69 kV-25 kV, 15/20/25 4 MVA transformer.
- Replace 76W-Mahone Bay transformer 76W-T1.
- Replace 96H-Ruth Falls transformer 96H-T1.
- Replace 77V-Conway transformer 77V-T1.
- Replace 92H-Tidewater Hydro transformer 92H-T61.
- Add a second 69-12.5kV transformer at 70W-Bridgewater.

The Western Valley Load Study has also recommended initiating the following projects in 2026:

- Install a 9 MVAR cap bank at 22W- Barrington Passage.
- Double Circuit Tower [7008] [7009] separation.
- Add new 138kV breaker in series with 99W-600.
- Add new 138kV breaker in series with 50W-600.
- 17V-T2 Transformer upgrade.
- 17V-T63 Transformer upgrade.
- 43V-C61 capacitor bank relocation to 43V-B62 or B63.
- New 69kV line L5515 with 556 ACSR Dove Conductor between 55V-Waterville Tap and L6015 tap through new 138kV to 69kV sub near L6015.
- New 138kV line L6617 with 795 ACSR Drake Conductor between 51V-Tremont and 70V-Bridgetown tap (35km) through new 138kV to 69kV sub near 70V-Bridgetown Tap.

2027

- Relocate 138kV-13.2kV, 7.5/10/12.5MVA Transformer 92H-T61 to 9C-Aberdeen to replace 9C-T1 and 9C-T2.
- Install a new 138/69 kV-25 kV, 15/20/25 MVA substation in Lower Truro tapped to Line L-5028.
- Add a second 25/33/42 MVA, 138 kV-25 kV transformer at new 98N-Stellarton Substation.
- Replace transformers 62N-T1 and 62N-T2 at end of expected life with a single 138/69 kV - 25 kV, 15/20/25 MVA transformer.
- Replace Auto-transformers 47C-T1 and 47C-T2 at Port Hawkesbury Paper (PHP).

2028

- Construct new 138 kV–25 kV, 25/33/42 MVA 127H-Fall River Substation complete with three 25 kV distribution feeders.
- Construct new 138 kV–25 kV, 25/33/42 MVA Substation near Stillwater Lake complete with three 25 kV distribution feeders.
- Construct new 138 kV–25 kV, 25/33/42 MVA Substation in Burnside (Windmill Rd)

complete with three 25 kV distribution feeders.

- Replace 74N-Springhill transformer 74N-T61.

2029

- Construct new 69/138 kV–25 kV, 25/33/42 MVA Eastern Passage Substation complete with three 25 kV distribution feeders. Add 5km, 69kV line tap to new substation from L-5011.
- Add a third 392 MVA, 230kV - 138kV transformer at 120H-Brushy Hill.

2030-2035

NS Power has several transmission and distribution planning studies in progress that are evaluating the following items for inclusion in future ACE Plans. The outcome of the studies referenced below may result in additional capital work, which will be reflected in future iterations of the 10-Year System Outlook report:

- Installation of new 138 kV Supply to 50V-Klondike and replace existing 69-25 kV transformer with new 15/20/25 MVA unit.
- Replace existing 7.5/10/12.5/14 MVA 22W - Barrington Passage transformer with 15/20/25 MVA unit and add additional feeder circuit.
- Replace existing 7.5/10//11.2 MVA 36V-Hillaton transformer with 15/20/25 MVA unit.
- Future 6-Breaker ring bus at 9W-Tusket to incorporate 9W-T2, 9W-T63, L6024, L6021, IR677 and Synchronous Condenser.

8.4 Generator Interconnection Related Project Work

There are twelve transmission projects associated with new generation projects connecting to the NS transmission system prior to 2030. They involve both Transmission Provider’s Interconnection Facilities (TPIF - facilities located between the Interconnection Customer’s substation and the Point of Interconnection) which are paid for by the Interconnection Customer but owned and operated by NS Power, and Network Upgrades (NUs) which are additions and upgrades on NS Power's side of the Point of Interconnection. Work associated with these facilities is not included in this 10YSO report.

8.5 Synchronous Condenser Installations

In order to accommodate the generation identified in Section 8.4, new synchronous condenser installations are required to be added to the NS Power transmission system by 2030. At present, six 55 MVA condensers have been identified for the following locations:

- IR-677 Substation: 1 unit
- 101V - MacDonald Pond: 1 unit with provision for a second unit
- 127C – Weavers Mountain: 1 unit
- 100N – Higgins Mountain: 1 unit
- 125C - Grosvenor: 2 unit

Each of these units will require their own 138kV or 230kV circuit breaker and substation terminal. Additional sync condensers are expected to be required to support the Green Choice procurement.

9.0 CONCLUSION

Customers count on NS Power for energy to power every moment of every day, and for solutions to power a sustainable tomorrow. Environmental legislation and policy initiatives in Canada and Nova Scotia continue to drive transformation of the NS Power electric power system. The Province's Clean Power Plan is progressing. NS Power's *The Path to 2030* and NS Power's Evergreen IRP modelling scenario CE1-E1-R2 continue to form the basis for the 2025 10-Year System Outlook report and reflect the current system planning environment at the time of this filing.