Nova Scotia Utility and Review Board

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

2024 10-Year System Outlook

NS Power

June 27, 2024

NON-CONFIDENTIAL

TABLE OF CONTENTS

1.0 Introduction 5
2.0 Load Forecast 7
3.0 Generation Resources 10
3.1 Existing Generation Resources 10
3.1.1 Maximum Unit Capacity Rating Adjustments 12
3.1.2 Mersey Hydro 13
3.1.3 Wreck Cove Hydro 14
3.2 Changes in Capacity 14
3.2.1 Path to 2030 and Evergreen IRP 14
3.2.2 Brooklyn Power 19
3.2.3 Lingan Unit 2 19
3.2.4 Annapolis Tidal 20
3.2.5 Rate Base Procurement 20
3.3 Unit Utilization Forecast 21
3.3.1 Evolution of the Energy Mix in Nova Scotia 21
3.3.2 Projections of Unit Utilization 22
3.3.3 Steam Fleet Utilization Outlook 24
4.0 Queued System Impact Studies 29
4.1 System Impact Studies (SIS) 31
4.2 OATT Transmission Service Queue 32
5.0 Environmental and Emissions Regulatory Requirements 34
5.1 Renewable Electricity Requirements 34
5.2 Environmental Regulatory Requirements 35
5.3 Anticipated Policy Changes – Clean Electricity Regulations 41
6.0 Resource Adequacy 44
6.1 Operating Reserve Criteria 44
6.2 Planning Reserve Criteria 45
6.3 Capacity Contribution of Renewable Resources in Nova Scotia 46
6.4 Load and Resources Review 48

7.0 Transmission Planning ... 51
7.1 System Description ... 51
7.2 Transmission Design Criteria ... 52
7.2.1 Bulk Power System (BPS) ... 53
7.2.2 Bulk Electric System (BES) ... 53
7.2.3 2023 Bulk Electric System Exception Requests ... 54
7.2.4 Remedial Action Schemes (RAS) ... 54
7.2.5 NPCC Directory 1 Review ... 54
7.2.6 NPCC Directory 7 Review ... 55
7.3 Transmission Life Extension ... 55
7.4 New Large-Load Customer Interconnection Requests ... 56
7.5 Reliability Tie ... 56
7.6 Western Valley Transmission System – Phase II Study ... 57
7.7 Hydrogen Load Impact Studies ... 58
7.8 EMT Studies to Support Wind Integration ... 59
7.9 NSPI System Inertia and Strength ... 60
7.9.1 System Inertia ... 60
7.9.2 System Strength ... 61
8.0 Transmission Development ... 62
8.1 Impact of Proposed Load Facilities ... 62
8.2 129H-Kearney Lake Relocation ... 63
8.3 Transmission Development Plans ... 63
9.0 Conclusion ... 67

LIST OF FIGURES

Figure 1: Net System Requirement with Future DSM Program Effects (actuals not weather adjusted) 7
Figure 2: Coincident Peak Demand and Future DSM Program Effects 9
Figure 3: 2024 Firm Generating Capacity for NS Power and IPPs 10
Figure 4: Firm Generating Capability for Wholesale Market Participants 12
Figure 5: Firm Capacity Changes & DSM 16
Figure 6: Additions and Retirements as in the 10-Year System Outlook Resource Plan 17
Figure 7: 2005, 2023 Actual and 2025 Forecast Energy Mix 22
Figure 8: NS Power Steam Fleet Unit Utilization Forecast 22
Figure 9: Utilization Factor 25
Figure 10: Forecast Unit Utilization Factors 26
Figure 11: Forecasted Sustaining Capital Investment by Unit 28
Figure 12: Combined T&D Advanced Stage Interconnection Queue as of June 24, 2024 29
Figure 13: Requests in the OATT Transmission Queue as of June 07, 2024 32
Figure 14: RES Compliance Forecast 35
Figure 15: Multi-year Greenhouse Gas Emission Limits 36
Figure 16: Greenhouse Gas Free Allowances 2019-2022 37
Figure 17: Emissions (SO_2, NOx, Hg) 37
Figure 18: NS OBPS Emission Intensity Standards 40
Figure 19: Marginal ELCC Percentage for New Wind Additions 46
Figure 20: NS Power 10-Year Load and Resources Outlook 49
Figure 21: NS Power Major Facilities in Service 2024 51

1.0 INTRODUCTION

NS Power 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 Nova Scotia Power's Path to 2030 - the company's Ten Year System Outlook 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[1], NSPSO System Planning, this report provides the 10-Year System Outlook on behalf of the Nova Scotia Power System Operator (NSPSO) for 2024. The 10-Year System Outlook is not an integrated resource planning exercise. It is the NSPSO's annual assessment of Nova Scotia Power Incorporated's (NS Power, Company) system capacity and resource adequacy.

The Report contains the following information:

- A summary of the NS Power load forecast and an update on the Demand Side Management (DSM) forecast in **Section 2.0.**
- A summary of generation expansion anticipated for facilities owned by NS Power and others in **Section 3.0**. NS Power's generation planning for existing facilities, including retirements as well as investments in upgrades, refurbishment or life extension, and new generating facilities committed in accordance with previously approved NSPSO system plans.

[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)."

- An updated list of Queued System Impact Studies in **Section 4.0.**
- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in **Section 5.0**. Section 5.0 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**.

Several changes in the planning environment have taken place since the 2023 10-Year System Outlook. In August of 2023, NS Power concluded its Evergreen IRP update and produced the Evergreen IRP Updated Action Plan and Roadmap[2] report. In October of 2023, the Province of Nova Scotia released the 2030 Clean Power Plan, providing a comprehensive path forward for the province, including NS Power, to meet the 2030 decarbonization goals of achieving 80 percent electricity sales from renewable resources and the phase-out of coal generation. Finally in December 2023, in compliance with the Nova Scotia Utility and Review Board (NSUARB, Board) direction arising from its 2023 ACE Plan Decision (M11017), NS Power filed The Path to 2030 report, providing detailed and specific information on how the Company will achieve its 2030 obligations; the Board subsequently included The Path to 2030 as an exhibit in the 2024 ACE Plan proceeding (M11458). The Evergreen IRP Updated Action Plan and Roadmap, the Province's 2030 Clean Power Plan, and NS Power's The Path to 2030 are aligned on approach to meeting 2030 environmental mandates.

The Evergreen IRP work assessed a range of future scenarios reflecting various potential system planning outcomes. Evergreen IRP scenario CE1-E1-R2 (net zero 2035, current policy and trends for electrification, no Atlantic Loop), in conjunction with specific projects with known timelines outlined in the 2030 Clean Power Plan and the Path to 2030 report, has been used as the basis for the 2024 10-year System Outlook report. Please refer to **Section 3.2.1** for a more detailed discussion of the Evergreen IRP and the selected reference scenario.

[2] Powering a Green Nova Scotia, Together: 2023 Evergreen IRP Updated Action Plan and Road Map (M11307), August 8, 2023. https://www.nspower.ca/docs/default-source/irp/evergreen-irp-update-to-irp-action-plan-and-roadmap-2023.pdf?sfvrsn=2865f7c2_1

2.0 LOAD FORECAST

The NS Power load forecast provides an outlook on the energy and peak demand requirements of customers in the province. The load forecast forms the basis for fuel and power-purchase supply planning, investment planning, and overall operating activities of NS Power. The figures presented in this Report are the same as those filed with the NSUARB in the 2024 Load Forecast Report[3] on April 30, 2024, and were developed using NS Power's statistically adjusted end-use (SAE) model to forecast the residential and commercial rate classes. The residential and commercial SAE models are 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).

Figure 1 shows historical and forecast NSR which includes in-province energy sales plus system losses. Compared to the 2023 Load Forecast, the 2024 Load Forecast shows higher growth in the near term due to more new customer additions and higher average use when adjusted for weather in 2023. Mid- to long-term growth is driven by sustained customer growth and Electric Vehicle (EV) sales, although estimated EV sales are lower than in 2023 due to the federal zero-emissions vehicle sales targets applying only at the national level, not the provincial level. Sales through the Renewable to Retail (RTR) market will reduce load in the 2025-2026 timeframe by approximately 250 GWh. In the long term, energy sales will be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs, as well as increased behind-the-meter solar installations. The net result of these updates is a forecast average annual net system requirement increase of 0.2 percent.

Figure 1: Net System Requirement with Future DSM Program Effects (actuals not weather adjusted)

Year	NSR (GWh)	Growth (%)
2014	11,037	-1.4
2015	11,099	0.6
2016	10,809	-2.6

[3] Nova Scotia Power 2024 Load Forecast Report (M11689), April 30, 2024.

Year	NSR (GWh)	Growth (%)
2017	10,873	0.6
2018	11,250	3.5
2019	11,077	-1.5
2020	10,723	-3.2
2021	10,902	1.7
2022	11,134	2.1
2023	11,131	0.0
2024F	11,490	3.2
2025F	11,409	-0.7
2026F	11,306	-0.9
2027F	11,347	0.4
2028F	11,416	0.6
2029F	11,448	0.3
2030F	11,514	0.6
2031F	11,523	0.1
2032F	11,585	0.5
2033F	11,605	0.2
2034F	11,695	0.8

NS Power also forecasts peak hourly demand for future years. The system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads. Due to the weather-sensitive load component in Nova Scotia, the system peak usually occurs in the period from December through February.

The peak demand forecast is developed using end-use energy forecasts combined with peak-day weather conditions to generate monthly peak demand forecasts through an estimated monthly peak demand regression model. The peak contribution from large customer classes is calculated from historical coincident load factors for each of the rate classes. Peak savings related to Demand Response (DR) activities, adjusted for Effective Load Carrying Capability (ELCC) as outlined in the 2022 Evergreen IRP and including Direct Load Control (DLC), Time Variable Pricing (TVP) and Business, Non-Profit and Institutional (BNI) Curtailment, are included in the firm peak. Customer growth, electrification of heating and increased EV sales increase the peak, while DSM and DR activities reduce the peak. Compared to 2023, the near-term peak forecast is higher due to an increase in heating intensity, likely due to increased hours of residential heating resulting from increased work-from-home activity but may also be driven by higher overall equipment intensity (higher temperature setpoints, more heating load served by the heat pumps), while in the long term the peak forecast is reduced due to lower EV sales and adoption of hybrid heating scenario in alignment with Nova Scotia's Clean Power Plan and NS Power's Evergreen IRP. As a result, the system peak is expected to increase at an average of 1.4 percent annually over the forecast period, as shown in **Figure 2**.

Figure 2: Coincident Peak Demand and Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2014	83	-	2,036	2,118	4.2
2015	141	-	1,874	2,015	-4.9
2016	98	-	2,013	2,111	4.8
2017	67	-	1,951	2,018	-4.4
2018	80	-	1,993	2,073	2.7
2019	111	-	1,949	2,060	-0.6
2020	96	-	1,954	2,050	-0.5
2021	94	-	1,875	1,968	-4.0
2022	155	-	2,061	2,216	12.6
2023	58	-	2,397	2,455	10.8
2024F	144	1	2,219	2,365	-3.7
2025F	144	4	2,259	2,408	1.8
2026F	149	12	2,267	2,428	0.8
2027F	148	24	2,265	2,437	0.4
2028F	148	36	2,283	2,466	1.2
2029F	148	39	2,306	2,493	1.1
2030F	148	39	2,360	2,547	2.2
2031F	147	39	2,397	2,583	1.4
2032F	147	38	2,438	2,623	1.5
2033F	147	38	2,485	2,670	1.8
2034F	147	38	2,542	2,727	2.1

As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, energy efficiency program effectiveness, economic activity, government policy, the impact of electrification, changes in large customer loads, the number of electric appliances and end-use equipment installed, and changes in technology.

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 when they are producing energy (e.g. wind, solar). This is discussed further in Section 3.3 below.

Figure 3 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 3.2.1). The firm generating capability for the wholesale market participants is set out in **Figure 4.**

Figure 3: 2024 Firm Generating Capacity for NS Power and IPPs

Plant/System	Fuel Type	Winter Net Capacity (MW)[4]
Avon	Hydro	6.4
Black River	Hydro	21.4
Lequille System	Hydro	23.0

[4] Winter Net Capacity is the maximum rated capacity during Nova Scotia winter peak period. Wind, Hydro and Solar are Effective Load Carrying Capability (ELCC) values. Please refer to Section 6.3 for further information.

Plant/System	Fuel Type	Winter Net Capacity (MW)[4]
Bear River System	Hydro	35.5
Tusket	Hydro	2.3
Mersey System[5]	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[6]	Hydro	0.0
Fall River	Hydro	0.5
Nova Scotia 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[7]	Coal/Pet Coke/Heavy Fuel Oil	607
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	168
Total Steam		**1547**
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-2001Renewables (firm)	IPPs	64.3
NS Power wind (firm)	Wind	14.5
Community-Feed-in-Tariff (firm)[8]	IPPs	29.6
Tidal IPP	Tidal	0.0

[5]The firm capacity for Mersey system is higher than represented in the 2023 10 Year System Outlook. This is a correction and aligns with the Mersey ELCC adjustment discussed in Section 3.1.2.
[6] Annapolis is assumed to be out of service. Please refer to Section 3.2.4.
[7] 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 3.2.3.
[8] 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.**

Plant/System	Fuel Type	Winter Net Capacity (MW)[4]
NS Power solar & Community solar (firm)	Solar	0.1
Total IPPs & Renewables		**134.2**
Total Capacity (NS Power and IPPs)		**2550.9**

Figure 4: Firm Generating Capability for Wholesale Market Participants

Wholesale Market Participant	Fuel Type	Winter Net Capacity[9] (MW)
Backup Top-Up (BUTU)[10]	Wind [Ellershouse][11]	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 [12] which was approved by Federal Energy Regulatory Commission (FERC) on March 20, 2014 and approved by the NSUARB 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 criteria are current. NS Power will continue to update unit maximum capacities in the 10-Year System Outlook each year as operational conditions change.

[9] 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.
[10] Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.
[11] Ellershouse wind farm is owned by the Alternative Resource Energy Authority (AREA).
[12] https://www.nerc.com/pa/Stand/Pages/Project2007-09-Generator-Verification.aspx

3.1.2 Mersey Hydro

The NS Power 2024 ACE Plan and Path to 2030 included sustaining capital investments in the Mersey Hydro System (MHS) which will ensure safe and reliable water management throughout the timeframe required to complete adequate preliminary engineering and stakeholder engagement to decide whether to redevelop or decommission the Mersey System. These sustaining investments are required regardless of whether the Mersey is ultimately redeveloped or decommissioned. The 2024 ACE Plan demonstrates that the deferral of the redevelopment decision regarding the Mersey Hydro System is the most economical option for customers.

In addition, the Mersey Hydro System continues to provide significant value to customers with a capacity of 45.8 MW, and an annual contribution toward NS Power's renewable energy generation targets of approximately 220 GWh. As NS Power moves toward 2030 with an increase in wind generation on the system and a requirement to reach 80 percent renewable electricity sales, the continued sustaining investment in the MHS supports the path to 2030 by providing both valuable capacity and renewable energy generation.

In the 2022 Evergreen IRP update, the Mersey Hydro System was modeled as being retained throughout the planning horizon. To account for the status of the redevelopment project work, the derated adjusted forced outage rate (DAFOR) was increased to account for potential additional outage hours on the Mersey Hydro System. The Effective Load Carrying Capability (ELCC) for Mersey has been reduced to 82 percent in the 2024 10 Year System Outlook; this is reflected in the firm generating capacity table (please see **Section 3.1**). The NERC equivalent forced outage rate (EFOR) stat for small hydro units was used as a proxy for the assumed DAFOR and the update reflects the most recent five year average (2018 – 2022) published in August of 2023. [13]

[13] https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

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. 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 2023 10-Year System Outlook the project schedule for the LEM Project anticipated a return to service of both Wreck Cove units ahead of the 2024/2025 winter peak period. However, subsequent revisions to the project schedule [14] show that Wreck Cove Unit 2 will be unavailable for the 2024/2025 winter peak period. Wreck Cove Unit 2 is currently expected to return to service ahead of the 2025/2026 winter peak period, providing 101 MW of firm capacity. This schedule is reflected in **Figure 21** and further discussed in **Section 6.4**.

3.2 Changes in Capacity

3.2.1 Path to 2030 and Evergreen IRP

In October of 2023, the Province of Nova Scotia's 2030 Clean Power Plan was released. This report outlines a plan to phase out coal and reach 80 percent renewable generation by 2030, as well as reduce greenhouse gas emissions by 90 percent from 2005 levels. In December 2023, NS Power filed The Path to 2030 report detailing the specific steps and actions to be undertaken to meet the

[14] M09596 - CI C0013838 Wreck Cove Life Extension and Modernization – Unit Rehabilitation and Replacement Contingency and Cost Minimization Report 2023 Q3, Sept 29, 2023

Province's decarbonization goals. Resource additions and retirements out to 2030 are informed by the details in these two documents.

For the purposes of the 2024 10-Year System Outlook Report, NS Power selected Evergreen IRP scenario CE1-E1-R2 (net zero 2035, current policy and trends electrification, no Atlantic Loop) to inform the resource mix for years 2031 to 2034. This is the planning scenario which is most closely aligned to the Province's Clean Power Plan, NS Power's The Path to 2030, and the 2024 Load Forecast. This scenario was among the lowest cost plans evaluated which achieves the 2030 decarbonization targets and the federal target of a net-zero electricity system in 2035.

NS Power will continue to be responsive to ongoing changes in the electricity planning environment, including but not limited to the pace of economy-wide electrification, and development of alternative peak mitigation strategies. NS Power will also monitor developments in emerging technologies in alignment with Federal policy discussion papers which point to these technologies as part of the path to a net-zero electricity system. The emerging technologies considered in the Evergreen IRP include hydrogen-fueled combustion turbines, small modular reactors (nuclear), tidal, natural gas generation with carbon capture and storage, and long duration energy storage. These resources are not currently commercially available but were evaluated as potential future resources in the Evergreen IRP modeling. Although they were not economically selected in the Evergreen IRP modeling within the timeframe of this report, NS Power will continue to monitor the development of these potential resources and reassess as needed. **Figure 5** below shows the anticipated DSM and firm capacity changes over the ten-year period starting in 2025.

Figure 5: Firm Capacity Changes & DSM

New Resources 2025-2034	Net MW
DSM Peak reduction	241
Demand Response (Firm contribution)[15]	38
Total Demand Side MW Change Projected Over Planning Period	**279**
Maintenance/Repairs:	
Hydro derates during Wreck Cove LEM	-101
Wreck Cove LEM Completion	101
Additions:	
Biomass[16]	43
Tidal (Firm Capacity)	1
New Wind Build - Rate Base Procurement (Firm Capacity)	31
New Wind Build - Green Choice Program (Firm Capacity)	33
Port Hawkesbury Paper Wind (Firm Capacity)	17
New Wind Build – Future Procurements (Firm Capacity)[17]	60
New Renewable to Retail Wind	15
Battery (Firm Capacity)	180
Diversity Credit (Solar + BESS)	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	**372**

A summary of the anticipated system additions and retirements is set out below in **Figure 6.** The timing of retirements has been updated from The Path to 2030 to account for increased firm peak demand reflected in the 2024 Load Forecast Report. See **Section 6.0** for further discussion on resource adequacy and planning reserve margin. Since many of the resource additions listed are

[15] Represents the firm contribution of demand response programs in 2034 assuming an ELCC of 48 percent. Refer to Section 2.0, Figure 2 for annual DR totals from 2025-2034.
[16] Port Hawkesbury Biomass transition from ERIS to NRIS
[17] Represents additional wind projects above and beyond the Rate Based Procurement Program or Green Choice Program from 2030-2034 in alignment with Evergreen IRP Scenario CE1-E1-R2.

currently in the development stage, there may be adjustments in timing for planned in-service dates and corresponding retirement dates. NS Power will continue to make adjustments as required.

Figure 6: Additions and Retirements as in the 10-Year System Outlook Resource Plan

Winter	Additions	Retirements
2024/2025	Tidal - Big Moon Tidal and NewEast Energy • Installed capacity: 4.8 MW • Firm capacity: 0.96 MW[18]	
2025/2026	Wind - Renewable to Retail • Installed capacity: 90 MW • Firm capacity: 9 MW[20] Battery Storage – NS Power BESS • Installed capacity: 100MW • Firm capacity: 72.1 MW[19]	

2026/2027	Wind - PHP Wind
	• Installed capacity: 168 MW,
	• Firm capacity: 16.8 MW[20]
	
	Wind - Rate Based Procurement
	• Installed capacity 306 MW,
	• Firm capacity: 30.6 MW[20]
	
	Wind - Renewable to Retail
	• New installed capacity 58.5 MW
	    • Total RTR capacity 148.5 MW
	• New firm capacity 6 MW[20]
	    • Total RTR firm capacity: 15 MW
	
	Battery Storage – NS Power BESS
	• Installed capacity: 50 MW
	• Firm capacity: 23.7 MW
	
	Solar - NS Community Solar Program
	• Installed capacity 25 MW
	• Firm capacity: 0 MW
	• Diversity capacity credit: 3 MW	

[18] The firm capacity contribution for Tidal is based on a marginal ELCC of 20 percent
[19] Battery Storage ELCC Percentage based on results of Planning Reserve Margin and Capacity Value Study, July 2019 by Energy and Environmental Economics, Inc
[20] Refer to Figure 20: Marginal ELCC Percentage for New Wind Additions for the marginal ELCC percentage applied to new wind additions in each period

Winter	Additions	Retirements
2027/2028	Combustion turbines • Installed capacity: 300 MW • Firm Capacity: 300 MW Battery Storage • Installed capacity 150 MW • Firm Capacity: 48.5 MW Solar - NS Community Solar Program • Installed capacity 25 MW • Firm capacity: 0 MW • Diversity capacity credit: 3 MW	• Trenton 5 (-150MW) • Lingan 2 (-148 MW)
2028/2029	Wind - Green Choice Program • Installed capacity 416 MW • Firm capacity 33.3 MW[20] Point Tupper 2 coal-to-gas conversation • Installed capacity 150 MW • Firm capacity: 150 MW Solar - NS Community Solar Program • Installed capacity 25 MW • Firm capacity: 0 MW • Diversity capacity credit: 3 MW	• Point Tupper 2 (-150MW)
2029/2030	Combustion turbines • Installed Capacity: 300 MW • Firm Capacity: 300 MW Battery Storage • Installed capacity 100 MW • Firm capacity: 36.1 MW Coal to HFO operation (Lingan 1, 3, 4) • Installed capacity 459 MW • Firm capacity: 459 MW Solar - NS Community Solar Program • Installed capacity 25 MW • Firm capacity: 0 MW • Diversity capacity credit: 3 MW	• Lingan 1, 3, 4 (- 459 MW) • Point Aconi (-168MW) • Trenton 6 (-154MW)
2030/2031	Wind – Future Procurements • Installed capacity: 300 MW • Firm capacity: 24 MW[20]	
2031/2032	Wind – Future Procurements	

Winter	Additions	Retirements
	• Installed capacity: 200 MW • Firm capacity: 12 MW[20]	
2032/2033	Wind – Future Procurements • Installed capacity: 200 MW • Firm capacity: 12 MW[20]	
2033/2034	Wind – Future Procurements • Installed capacity: 200 MW • Firm capacity: 12 MW[20]	

3.2.2 Brooklyn Power

Brooklyn Power owns a 24 MW firm dispatchable renewable energy biomass facility located in Liverpool, Nova Scotia. NS Power purchases energy from Brooklyn Power under a long-term power purchase agreement (PPA). On February 18, 2022 high winds caused damage to the unit's power stack and warehouse, ultimately taking the unit offline. Repairs to the facility were completed and the facility has been back online since early 2023.

3.2.3 Lingan Unit 2

Effective August 15, 2022, Lingan Unit 2 was laid up and not made available for economic dispatch. The unit was placed into cold reserve and available to be recalled on two weeks' notice. Over the 2023/2024 Winter period the unit was recalled to service five times by the NSPSO to support firm customer load, generating a total of 67.6 GWh.

NS Power has identified a need for additional firm capacity due to an increase in forecast firm peak energy (**Section 2.0**). Lingan 2 will therefore continue to be held in cold reserve for several years to maintain planning reserve margin. 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.

3.2.4 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 NSUARB[21] 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 NSUARB concluded that it was not yet in a position to find the asset Not Used and Not Useful. The NSUARB will reconsider the application for the requested accounting treatment if NS Power resubmits it with a decommissioning application. NS Power is continuing capital planning activities with respect to the generating station and is engaging in discussions with Fisheries and Oceans Canada.

NS Power provided a status update to the NSUARB on March 9, 2023 indicating that the Company, along with the relevant environmental regulators (DFO), continues to assess the Annapolis Tidal Generating Station. In subsequent updates to the NSUARB on July 31, 2023 and January 30, 2024, 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 Decision Analysis is being updated regarding the future of Annapolis Tidal Generating Station. Another update will be provided to the NSUARB on July 31, 2024. For the purposes of the 2024 10-Year System Outlook, NS Power has assumed no capacity or energy contribution from the Annapolis Tidal Generating Station.

3.2.5 Rate Base Procurement

The Rate Base Procurement (RBP) program was initiated by the Province of Nova Scotia in 2021. The goal of the RBP was to contract for 1100 GWh of low-impact renewable electricity per section

[21] 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.

6B(2)(b) of the Renewable Electricity Regulations[22] as part of meeting NS Power's 2030 Decarbonation Goals.

The RBP portfolio was announced on August 17, 2022 and subsequently updated on July 12, 2023 and February 8, 2024. The RBP Portfolio initially included five (5) projects totalling 373MW and 1,478 GWh of new wind generation to the Nova Scotia System, each of which were awarded a Power Purchase Agreement (PPA). Since that time, one of the projects awarded a PPA withdrew from the program and a potential replacement project will not proceed under the RBP program. The RBP Program now includes four (4) projects totaling 306MW and 1,165 GWh of wind generation. These projects are anticipated to be in-service on or before December 31, 2026. For the 2024 10 Year System Outlook it is assumed the capacity and energy represented by the withdrawn RBP wind project will be added to the Green Choice procurement round increasing the maximum nameplate capacity of all generation facilities accepted into the Green Choice Program from 350 MW to 416 MW.

3.3 Unit Utilization Forecast

The Company typically forecasts 10 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.

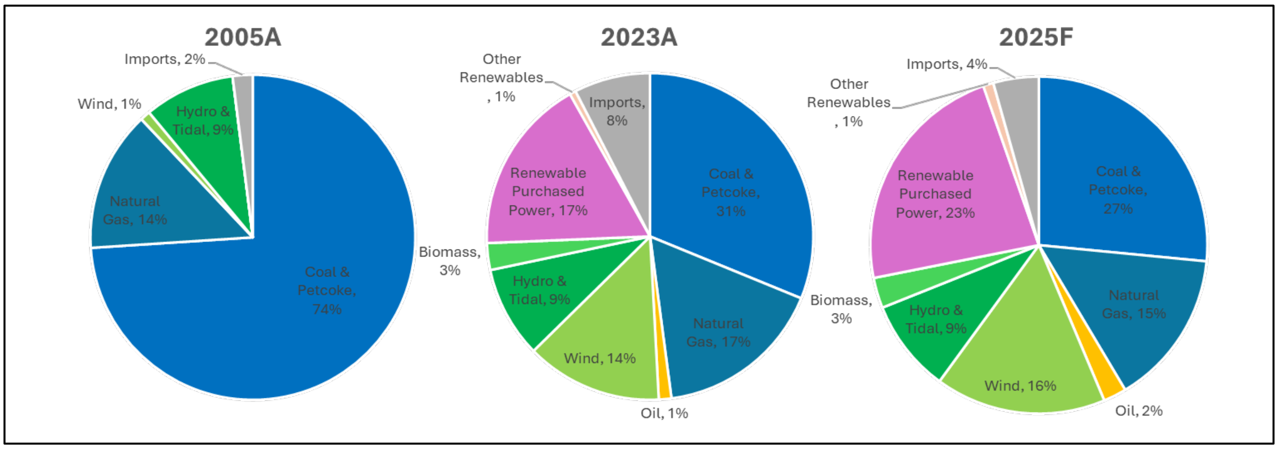
3.3.1 Evolution of the Energy Mix in Nova Scotia

NS Power's energy production mix has undergone significant changes over the last 15 years. Since the implementation of the RES, an increased percentage of energy sales is produced by variable renewable resources such as wind. However, due to their intermittent nature, variable resources provide less firm capacity, as a percentage of net operating capacity, than conventional generation

[22] N.S. Reg. 155/2010 as amended to N.S. Reg. 338/2022

resources. Therefore, the majority of the system requirement for firm capacity and other ancillary services is met with NS Power's conventional units (i.e. coal, gas, diesel, hydro) as discussed in **Section 3.1**, while the energy output of conventional units is being displaced by renewable resources. **Figure 7** below illustrates this change with the actual energy mix from 2005 and 2023 and the updated forecast for 2025.

Figure 7: 2005, 2023 Actual and 2025 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 8**.

Figure 8: NS Power Steam Fleet Unit Utilization Forecast

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lingan 1 [23]	Capacity Factor (%)	40	35	17	31	9	1	1	2	1	1
	Unit Cycles	19	10	19	16	8	6	4	5	5	6
	Service Hours	6348	4894	2689	3417	791	116	103	183	142	107
Lingan 2 [24]	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

[23] Lingan units 1, 3, 4 operate on HFO from 2030-2034
[24] Lingan unit 2 will be held in cold reserve, recallable to service as needed until 2027. See **Section 3.2.3**.

Lingan 3[24]	Capacity Factor (%)	20	21	17	20	12	1	2	2	2	1
	Unit Cycles	44	18	23	25	12	7	8	10	7	6
	Service Hours	3215	3407	2526	2157	1043	171	209	273	242	172
Lingan 4[24]	Capacity Factor (%)	24	25	21	31	10	2	1	2	2	2
	Unit Cycles	35	19	23	25	15	5	6	7	7	8
	Service Hours	4014	3786	3034	3342	880	176	182	247	222	179
Point Aconi	Capacity Factor (%)	71	81	22	12	5	0	0	0	0	0
	Unit Cycles	7	6	8	5	3	0	0	0	0	0
	Service Hours	6739	7555	2592	1264	481	0	0	0	0	0
Point Tupper[25]	Capacity Factor (%)	19	16	38	8	25	2	1	2	2	2
	Unit Cycles	15	9	10	3	14	8	9	10	5	9
	Service Hours	2320	1616	3283	674	2923	254	161	270	219	232
Trenton 5	Capacity Factor (%)	14	12	23	0	0	0	0	0	0	0
	Unit Cycles	4	3	4	0	0	0	0	0	0	0
	Service Hours	1449	1240	2008	0	0	0	0	0	0	0
Trenton 6	Capacity Factor (%)	58	57	63	48	12	0	0	0	0	0
	Unit Cycles	3	3	10	23	11	0	0	0	0	0
	Service Hours	7872	7872	6931	4722	1024	0	0	0	0	0
Tufts Cove 1	Capacity Factor (%)	38	14	22	11	18	5	3	5	4	2
	Unit Cycles	12	4	19	11	34	14	7	12	11	7
	Service Hours	4437	1597	2365	1017	1688	447	285	467	367	207
Tufts Cove 2	Capacity Factor (%)	44	25	33	35	37	20	16	17	12	12
	Unit Cycles	29	27	20	30	61	62	65	46	45	56
	Service Hours	5280	2558	4208	3534	3562	2142	1676	1679	1240	1235
Tufts Cove 3	Capacity Factor (%)	49	34	41	42	54	30	23	28	21	18
	Unit Cycles	39	40	27	35	55	89	83	80	79	71
	Service Hours	5788	3677	5242	4221	5442	3340	2525	3067	2322	1914
Tufts Cove 4	Capacity Factor (%)	73	77	80	80	80	62	56	57	43	39
	Unit Cycles	67	44	52	84	81	222	214	209	206	224

[25] Point Tupper is converted to Natural Gas in 2028

	Service Hours	7120	7033	7544	7287	7279	5822	5240	5355	4051	3677
Tufts Cove 5	Capacity Factor (%)	55	71	79	82	80	62	55	57	44	38
	Unit Cycles	158	97	52	77	83	237	221	206	218	250
	Service Hours	5877	6532	7446	7419	7258	5827	5186	5379	4120	3551
Tufts Cove 6	Capacity Factor (%)	30	35	53	59	61	45	40	41	34	30
	Unit Cycles	35	40	22	49	55	161	159	145	161	175
	Service Hours	6467	7196	7195	6986	6884	5598	5074	5225	4082	3501
PH Biomass	Capacity Factor (%)	52	51	53	58	63	66	60	45	36	46
	Unit Cycles	99	100	158	171	156	160	175	193	204	219
	Service Hours	5662	5571	5377	5930	6065	6522	5957	4812	4045	4868

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 9** below.

Figure 9: 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 the PLEXOS dispatch optimization model to derive utilization forecasts and qualitatively assess the UF of each unit by evaluating the components described above**. Figure 10** below provides the UF by each unit on an annual basis.

Figure 10: Forecast Unit Utilization Factors[26]

Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
LIN-1 – Coal	M	H	M	M	M	L	-	-	-	-	-
LIN-2 – Coal	UL	UL	UL	UL	-	-	-	-	-	-	-
LIN-3 – Coal	M	M	M	M	M	L	-	-	-	-	-
LIN-4 – Coal	M	M	M	M	M	L	-	-	-	-	-
LIN-1 – HFO[27]	-	-	-	-	-	-	UL	UL	UL	UL	UL
LIN-3 – HFO[2727]	-	-	-	-	-	-	UL	UL	UL	UL	UL
LIN-4 – HFO[2627]	-	-	-	-	-	-	UL	UL	UL	UL	UL
POA-1	H	H	H	M	L	UL	-	-	-	-	-
POT-2 – Coal	M	L	L	M	UL	-	-	-	-	-	-
POT-2 – Gas[28]	-	-	-	-	-	M	UL	UL	UL	UL	UL

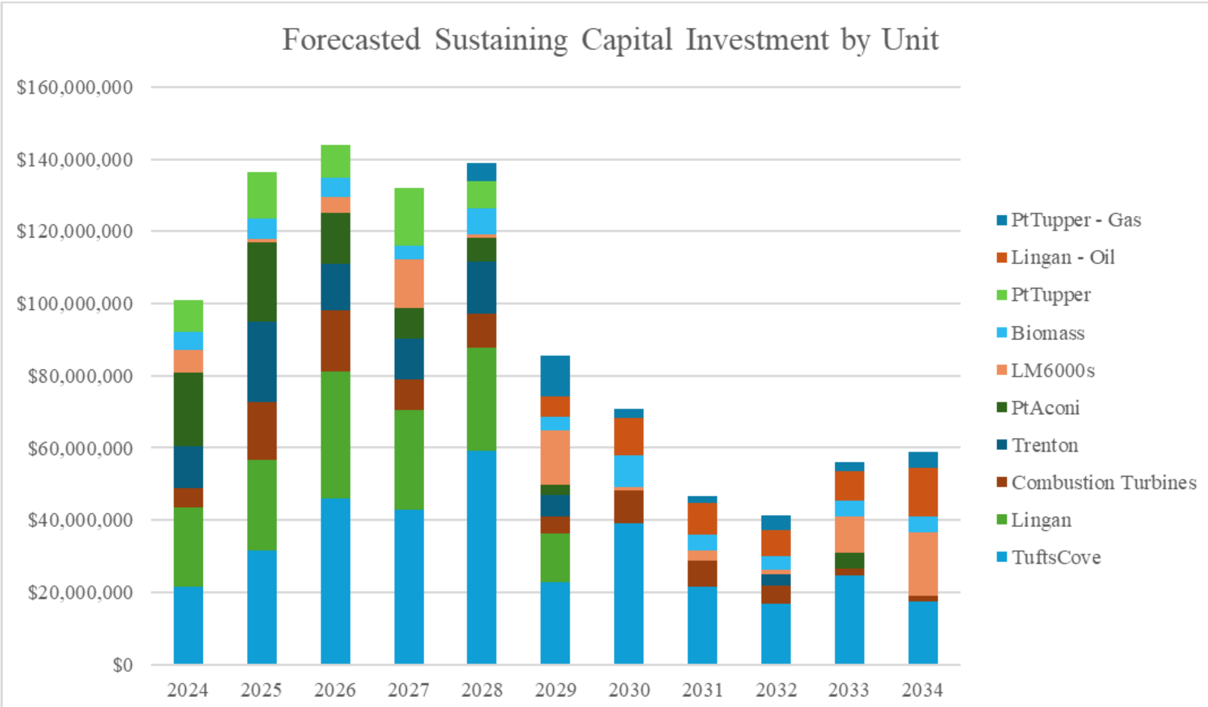
[26] H=High, M=Medium, L=Low, UL = Ultra Low
[27] LIN-1, LIN-3, LIN-4 values from 2030 onwards reflect operation on Heavy Fuel Oil (HFO).
[28] POT-2 values from 2029 onwards reflect operation post natural gas conversion.

Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
TRE-5	L	L	L	L	-	-	-	-	-	-	-
TRE-6	H	H	H	H	M	L	-	-	-	-	-
TUC-1	M	M	L	L	L	L	UL	UL	UL	UL	UL
TUC-2	H	M	M	M	M	H	H	H	M	M	H
TUC-3	H	H	M	H	M	H	H	H	H	H	H
TUC-4	H	H	H	H	H	H	H	H	H	H	H
TUC-5	H	H	H	H	H	H	H	H	H	H	H
TUC-6	H	H	H	H	H	H	H	H	H	H	H
PHB-1	H	H	H	H	H	H	H	H	H	H	H

Figure 11 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 possible to reduce large investments in the thermal fleet.

Figure 11: Forecasted Sustaining Capital Investment by Unit[29]



[29] All values in 2024 Dollars. Forecast Investments are subject to change arising from asset health and actual utilization. Changes in currency value, escalation and inflation can also have significant effect on actual cost.

4.0 QUEUED SYSTEM IMPACT STUDIES

Figure 12 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 12: Combined T&D Advanced Stage Interconnection Queue as of June 24, 2024

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	ME Winter	Inter-connection Point	Type	In-Service Date (Commercial Operation) DD-MMM-YY[30]	Status	Service Type
2 - T	516	05-Dec-14	Cumberland	1.26	1.26	37N	Tidal	30-Jun-23	GIA Executed	NRIS
3 - T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	31-Oct-23	GIA Executed	NRIS
4 - T	542	26-Sep-16	Cumberland	3.78	3.78	37N	Tidal	30-Jun-25	GIA Executed	NRIS
5 - D	557	19-Apr-17	Halifax	7.0	7.0	24H	CHP	01-Sep-18	SIS Complete	N/A
6 - T	517	15-Dec-14	Cumberland	4.00	4.00	37N	Tidal	01-Oct-19	GIA in Progress	NRIS
7 - D	569	26-Jul-19	Digby	0.6	0.6	509V-302	Tidal	21-Feb-24	GIA Executed	N/A
8 - D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	30-Apr-22	GIA Executed	N/A
9 - T	574	27-Aug-20	Hants	58.80	58.80	L-6051	Wind	30-Sep-25	GIA Executed	NRIS
10 - T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	30-Jun-24	GIA Executed	NRIS

[30] The in-service dates listed reflect the milestone dates specified in the interconnection agreement with the Interconnection Customer associated with each individual Interconnection Request or as last specified by the Interconnection Customer in interconnection study related agreements.

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	ME Winter	Inter-connection Point	Type	In-Service Date (Commercial Operation) DD-MMM-YY[30]	Status	Service Type
12 - T	597	07-May-21	Queens	36.00	36.00	50W	Wind	30-Sep-25	GIA Executed	NRIS
13 - T	647	06-Oct-21	Cumberland	1.50	1.50	37N	Tidal	31-Dec-23	GIA in Progress	NRIS
15 - D	654	16-Feb-22	Halifax	0.125	0.125	127H-413	Solar	20-Sep-22	GIA Executed	N/A
16 - T	664	26-Jul-22	Lunenburg	50.00	50.00	99W	Battery	7-Nov-25	FAC Complete	NRIS
17 - T	662	26-Jul-22	Halifax	50.00	50.00	132H	Battery	24-Nov-25	FAC Complete	NRIS
18 - T	670	05-Aug-22	Colchester	94.40	94.40	L-7005	Wind	28-Feb-26	FAC Complete	NRIS
19 - T	671	05-Aug-22	Halifax	88.96	88.96	L-6004	Wind	28-Feb-26	FAC in Progress	NRIS
20 - T	669	04-Aug-22	Cumberland	99.00	99.00	L-6613	Wind	31-Dec-25	FAC Complete	NRIS
21 - T	668	03-Aug-22	Antigonish	94.40	94.40	L-7003	Wind	01-Apr-26	FAC Complete	NRIS
22 - T	618	21-Jul-21	Guysborough	130.20	130.20	L-7003	Wind	30-Sep-25	FAC Complete	NRIS
23 - T	673	09-Aug-22	Hants	33.60	33.60	L-6054	Wind	31-Dec-24	FAC Complete	NRIS
24 - T	675	10-Aug-22	Queens	112.50	112.50	50W	Wind	01-Dec-24	FAC Complete	NRIS
25 - T	677	23-Sep-22	Yarmouth	80.00	80.00	L-6024	Wind	31-Dec-25	SIS in Progress	NRIS
26 - D	676	15-Aug-22	Halifax	0.74	0.65	103H-431	Solar	01-Aug-25	GIA Executed	N/A
27 - T	697	28-Mar-23	Kings	50.00	50.00	43V	Battery	21-Aug-26	SIS in Progress	NRIS
28 - D	699	18-Apr-23	Halifax	0.63	0.63	58H-431	Solar	31-Dec-24	GIA Executed	N/A
29 - D	700	21-Apr-23	Cape Breton	0.56	0.56	82S-303	Solar	30-Sep-23	SIS Complete	N/A
31 - T	686	23-Jan-23	Cumberland	340.00	340.00	L-8001	Wind	01-Dec-25	SIS in Progress	NRIS
32 - D	711	05-Jul-23	Halifax	0.48	0.48	139H-411	Solar	31-Oct-23	SIS Complete	N/A

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	ME Winter	Inter-connection Point	Type	In-Service Date (Commercial Operation) DD-MMM-YY[30]	Status	Service Type
33 - D	712	05-Jul-23	Halifax	0.30	0.30	139H-411	Solar	31-Oct-23	SIS Complete	N/A
34 - T	739	20-Sep-23	Queens	90.00	90.00	L-6025	Wind	31-Dec-25	SIS in Progress	NRIS
35 - T	742	13-Oct-23	Guysborough	35.00	35.00	L-7003	Wind	01-Jan-25	SIS in Progress	NRIS
36 - D	716	03-Aug-23	Halifax	0.24	0.24	139H-412	Solar	01-Oct-23	GIA Executed	N/A
38 - D	741	28-Sep-23	Cumberland	5.07	4.07	3N-412	Solar	01-Dec-24	GIA in Progress	N/A
39 - D	743	24-Oct-23	Cape Breton	0.13	0.13	67C-411	Solar	15-Mar-24	GIA Executed	N/A
40 - D	750	20-Nov-23	Annapolis	0.25	0.25	70V-312	Solar	31-Mar-24	SIS in Progress	N/A
41 - D	752	01-Jan-24	Hants	0.19	0.19	1N-402	Solar	15-Mar-24	SIS in Progress	N/A
42 - D	754	24-Jan-24	Yarmouth	0.33	0.33	88W-314	Solar	30-Apr-24	SIS in Progress	N/A
43 - D	757	12-Feb-24	Halifax	0.74	0.74	103H-431	Solar	01-Oct-24	SIS in Progress	N/A
44 - D	740	08-Sep-23	Hants	0.25	0.25	20V-311	Solar	01-Jan-25	SIS in Progress	N/A

4.1 System Impact Studies (SIS)

As outlined in **Figure 12** above, a significant number of SIS and the subsequent FAC have been completed or are in progress. Of the SIS either in progress or complete, the majority are studying 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 related to the coal-fired generation phase-out requirement by 2030, GIP SIS are being expanded to include Electromagnetic Transient (EMT) Analysis in addition to Load Flow and Dynamic Analysis. This change was required to understand the impacts of IBR interconnections and requirements to maintain system reliability and stability. Each transmission SIS initiated for Study

Group 32 or beyond requires EMT analysis as part of their SIS to determine if additional equipment is required to support the integration of the new generation resource.

4.2 OATT Transmission Service Queue

As of June 07, 2024 there are two active requests in the Open Access Transmission Tariff (OATT) Transmission Queue as shown in **Figure 13.**

Figure 13: Requests in the OATT Transmission Queue as of June 07, 2024

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*	May 2019	330	System Upgrades in Progress
2	TSR 411	January 19, 2021	Point-to-point	NS-NB*	January 1, 2028	550	Facilities Study in Process

*Indicates project as being located near provincial border.

Information in **Figure 13** 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[31] 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.

[31] 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

The design for the remaining system upgrades related to Transmission Service Request (TSR) 400 was completed in 2022. The execution of the remaining upgrades is planned for 2024/2025.

A Facilities Study (FAC) is currently in progress for TSR 411.

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 3.2.5** above for details on the associated Rate Base Procurement program.

On April 8, 2016 the Province amended the Renewable Electricity Regulations to allow NS Power to include COMFIT projects in its RES compliance planning. It also amended the Regulations to remove the "must-run" requirement of the Port Hawkesbury biomass generating facility.[32] From 2015 to 2019 the Company served 26.6 percent (2015), 28 percent (2016), 29 percent (2017), 30 percent (2018) and 30 percent (2019) of sales using qualifying renewable energy sources.

The Nova Scotia Block of the Muskrat Falls energy from Newfoundland & Labrador began delivery over the Maritime Link on August 15, 2021. However, ongoing issues prevented the full delivery of energy from Muskrat Falls, and the Company was unable to meet the 40 percent renewable energy standard over the three calendar years 2020-2022. For the years 2020-2023, the Company served 29 percent (2020), 30.4 percent (2021), 36 percent (2022) and 42.5 percent (2023) of sales using qualifying renewable energy sources.

The near-term RES Compliance Forecast in **Figure 14** illustrates the full amount of RES-eligible energy forecast to be available to the Company for 2025-2027.

[32] *Renewable Electricity Regulations*, made under Section 5 of the *Electricity Act* S.N.S. 2004, c. 25 O.I.C. 2010-381 (effective October 12, 2010), N.S. Reg. 155/2010 as amended to O.I.C. 2020-147 (effective May 5, 2020), N.S. Reg. 74/2020 s. 5(2A).

Figure 14: RES Compliance Forecast

RES Compliance Forecast			
	2025	**2026**	**2027**
Energy Requirements (GWh)			
NSR Including DSM effects	11,409	11,306	11,347
Losses	763	750	751
Sales	10,646	10,556	10,596
RES (%) Requirement	40	40	40
RES Requirements (GWh)	**4,258**	**4,222**	**4,238**
Renewable Energy Sources (GWh)			
NS Power Wind	222	222	246
Post-2001 IPPs	749	1,090	1,179
PH Biomass	130	117	200
COMFIT Wind Energy	481	481	525
COMFIT Non-Wind Energy	13	13	6
Eligible Pre-2001 IPPs	141	141	51
Eligible NSPI Legacy Hydro	926	926	907
REA Procurement (South Canoe/Sable)	307	326	328
Rate Based Procurement Wind[33]			1085
Compliant Renewable Import	2,418	2,433	2,235
Forecast Renewable Energy (GWh)	**5,388**	**5,750**	**6,759**
Forecast Surplus or Deficit (GWh)	**1,130**	**1,528**	**2,527**
Forecast RES Percentage of Sales	**51%**	**54%**	**64%**

5.2 Environmental Regulatory Requirements

The Nova Scotia Greenhouse Gas Emissions Regulations[34] specify emission caps for 2010-2030, as outlined in **Figure 15.** 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.

[33] Rate Based Procurement wind is conservatively forecasted to be fully operational and available January 1, 2027. Some energy may become available sooner as projects are anticipated to begin to come online in late 2026.
[34] *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.

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 15: Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes (CO_2)
2010-2011	19.22
2012-2013	18.5
2014-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

From 2019 to 2022, Nova Scotia's cap-and-trade program was in effect. The Cap-and-Trade Program Regulations included annual free allowances for GHG emissions for NS Power for the period from 2019 to 2022. NS Power's free emission allocations over the four year compliance period were 22,058,000 tonnes of CO2eq. Under the GHG cap-and-trade system, NS Power was limited to purchasing no more than 5 percent of GHG credits offered for auction by the province. NS Power met the requirements of the program through reduced emissions and the amendment to the Cap-and-Trade Regulations, which provided NS Power with 2,600 additional kilotonnes.

Figure 16: Greenhouse Gas Free Allowances 2019-2022

Year	GHG Free Allowances Million tonnes
2019	6.334
2020	5.517
2021	5.120
2022	5.087

The Nova Scotia Air Quality Regulations[35] specify emission caps for sulphur dioxide (SO_2), 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 SO_2 and NOx.

The Province introduced amendments to the Air Quality Regulations respecting the SO_2 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 SO_2. The revised emissions requirements are shown below in **Figure 17.**

Figure 17: Emissions (SO_2, NOx, Hg)

Multi-Year Caps Period	SO_2 Tonnes			NOx Tonnes		Mercury Kg
	Unit Maximum	Annual	Cumulative	Annual	Cumulative	Annual
2021-2022	17,760	60,900	90,000	14,955	56,000	35

[35] *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.

Multi-Year Caps Period	SO_2 Tonnes			NOx Tonnes		Mercury Kg
	Unit Maximum	Annual	Cumulative	Annual	Cumulative	Annual
2023-2024	17,760	60,900	68,000	14,955		35[36]
2025	13,720	28,000		11,500		35[36]
2026-2029	13,720	28,000	104,000[37]	11,500	44,000	35
2030	9,800	20,000		8,800		30

In the 2021-2022 compliance period NS Power exceeded the SO_2 limit by 14 kilotonnes and exceeded the mercury emission limit by 6.7 kg. The SO_2 exceedance will be recovered between 2026 and 2029 as NS Power does not expect to emit to the SO_2 limits as new renewable resources are added to the system during this time period. 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, the remaining 1.6 kg of excess mercury emission will be made up over the 2024-2025 period.

SO_2 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

[36] An excess of 6.7kg of mercury emitted in 2021-2022 must be compensated for by reducing annual emissions by 6.7kg in aggregate below the annual 65kg limit between 2023 and 2025
[37] An excess of 14kt of SO_2 emitted in 2021-2022 must be compensated for by reducing emissions by 14kt in aggregate below the total annual limits between 2027 and 2029

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.

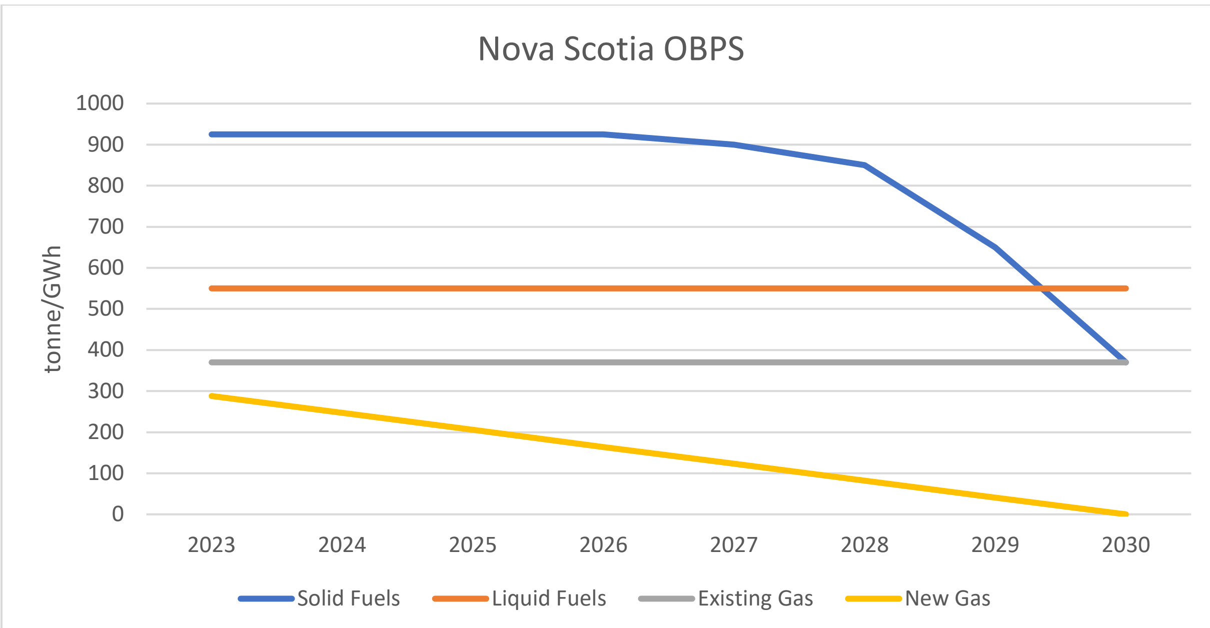
In December 2020, as part of the report titled A Healthy Environment and a Healthy Economy,[38] the Federal Government proposed a carbon price trajectory of $65/tonne starting in 2023 and rising $15 annually to $170/tonne in 2030 ("Federal Backstop"). Following this report, additional information from both the Federal Government and the Province provided further guidance on the carbon policy requirements related to both the carbon price and how this would be enabled in the provinces. In July 2021, the Federal Government confirmed the Federal Backstop and referenced potential requirements for a provincial system to be found equivalent to the Federal Backstop. In January 2022, the Federal Government confirmed the program options for the Province to enact the carbon policy which include meeting the Federal Backstop carbon pricing for emissions produced, extending the cap-and-trade program or enabling a hybrid model in which a performance target is established, which retains a marginal price signal to incent emissions reductions.

In October 2022, the Province updated the Environment Act,[39] 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.

[38]https://www.canada.ca/en/environment-climate-change/news/2020/12/a-healthy-environment-and-a-healthy-economy.html
[39] Nova Scotia Legislature – Bill No. 208: c046.pdf (nslegislature.ca)

The Province received federal approval late in 2022 for the NS OBPS, which establishes a performance standard by facility type for the electricity sector beginning in 2023. The performance standards for the NS OBPS by fuel type are shown in **Figure 18**.

Figure 18: NS OBPS Emission Intensity Standards



The Province introduced the Environmental Goals and Climate Change Reduction Act (EGCCRA) on October 27, 2021.[40] 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.

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

5.3 Anticipated Policy Changes – Clean Electricity Regulations

In the spring of 2022, the Federal Government (Environment and Climate Change Canada, ECCC) published a discussion paper on a potential Clean Electricity Standard (CES).[41] The focus of the discussion paper was on the Federal Government's commitment to target net-zero electricity production by 2035, in support of achieving net-zero emissions economy-wide by 2050. Offsets/credits are being considered as an element of the CES framework, which would serve to offset emissions from electricity generation in support of economy wide electrification. In parallel, the OBPS emissions performance standards will be reviewed within the context of meeting the 2035 targets and beyond.

Following the discussion paper and a period of industry engagement, ECCC released a proposed frame[42] for a Clean Electricity Regulation under the Canadian Environmental Protection Act (CEPA) in July 2022, which will establish the performance standards and operating parameters for emitting generation in 2035 and beyond. NS Power participated in the consultation phase leading up to the fall of 2022 and ECCC ended the initial phase of consultation in advance of Canada Gazette 1 publication.

On August 19, 2023, the Federal Government released the Clean Electricity Regulations under Canada Gazette 1 (CG1).[43] As part of the formal engagement process under CG1 (November 2023), NS Power engaged with ECCC (policy and modeling) and provided the following feedback to ECCC:

- Additional flexibility is required to operate NS Power's emitting fleet to maintain system reliability and meet customer demand during peak periods and support the integration of wind resources.

[41] A clean electricity standard in support of a net-zero electricity sector: discussion paper - Canada.ca
[42] Proposed Frame for the Clean Electricity Regulations - Canada.ca
[43] CER Under CG1: Canada Gazette, Part 1, Volume 1, Number 1: Clean Electricity Regulations

- NS Power's modeling demonstrates that operating its emitting fleet in a peaking capacity (with low annual capacity factors) supports system reliability while still reducing overall system emissions.

On February 16, 2024, ECCC provided an update to stakeholders reflecting the feedback received and proposed changes to the CER,[44] which indicated the following:

- The proposed changes acknowledged the importance of emitting generation in supporting the integration of variable renewable generation (wind, solar) to support the safe and reliable operation of the grid while reducing overall system emissions.

- The proposed changes included the following, which are the most impactful to NS Power:
  - Increased flexibility to efficiently operate (reduce emissions and system cost) the generating fleet through emissions caps by facility, of which the allowable emissions can be pooled.
  - Adjustment of the performance standard that informs unit emission limits.
  - The use of offsets for utilities who have operated in good faith but have exceeded the limits.
  - Changes to the "first generation" date for new emitting generation and the applicable operating requirements.
  - Enabling emergency provisions that reflects the needs of the utility to manage assets during emergency conditions.

NS Power will continue to engage with ECCC as part of the formal stakeholder engagement period; the release of the updated CER as part of Canada Gazette 2 (CG2) is anticipated in Q4 2024. Following the finalization of the regulations, NS Power will undertake an assessment to understand the impacts of the CER on the long-term strategy and IRP Action Plan, in accordance with the Evergreen IRP Action Plan and Roadmap Update, Roadmap Item 5.

[44] Update to CER: Canada Gazette, Part 1, Volume 1, Number 1: Clean Electricity Regulations

NS Power continues to engage with both levels of government to explore opportunities to meet the Company's carbon reduction obligations in a way that is affordable for customers and maintains electricity supply reliability.

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 NSUARB. The criteria require that:

> Each Balancing Authority shall have ten-minute reserve available that is at least equal to its first contingency loss…and,
>
> Each Balancing Authority shall have thirty-minute reserve available that is at least equal to one half its second contingency loss.[45]

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 168MW 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 Nova Scotia Power Incorporated and New Brunswick Power Corporation. Additional regulating reserve is maintained to manage the variability of customer load and generation.

[45] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories

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 wind 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 NSUARB. 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.[46]

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[47] 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**.

[46] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories
[47] 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, renewable energy resources such as wind and solar are not always available to contribute during peak demand hours. The Effective Load Carrying Capability (ELCC), or "capacity value" of a resource represents the statistical likelihood that it will be available to serve the firm peak demand, and as a result, what percentage of its 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 these intermittent renewable resources.

In a letter dated October 5, 2018 [48] the NSUARB directed NS Power to complete certain pre-IRP analyses by July 31, 2019. One of the pre-IRP deliverables directed by the NSUARB 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) [49] 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.

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 2024		611		
2024/2025	0	611		

[48] UARB Decision Letter, Generation Utilization and Optimization, M08059, October 5, 2018.
[49] 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/

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)
2025/2026	90	701	10%	9
2026/2027	534	1235	10%	53.4
2007/2028	0	1235		
2028/2029	416	1651	8%	33.3
2029/2030	0	1651		
2030/2031	300	1951	8%	24
2031/2032	200	2151	6%	12
2032/2033	200	2351	6%	12
2033/2034	200	2551	6%	12

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 NSUARB 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.

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).

Municipal load for Berwick, Mahone Bay, Antigonish, and Riverport is served by a wind farm owned by Alternative Resource Energy Authority (AREA). This generation is not included in NS Power's sourced wind generation but contributes to operational considerations of the total amount of wind generation on the Nova Scotia system.

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 5** 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 Clean Power Plan, with slight modifications to new firm resource requirements and coal unit retirement timing to account for the updated firm peak demand reflected in the 2024 Load Forecast. [50]

With an increase of 108 MW in the forecast firm peak for 2024, as noted in the 2024 Load Forecast Report, and a delay in the Wreck Cove LEM Project, pushing the return to service of Wreck Cove Unit 2 and its 101 MW of firm capacity past the 2024/2025 Winter period, as discussed in **Section 3.1.3**, NS Power will not achieve the target 20 percent PRM for the 2024/2025 Winter period. In order to mitigate challenges with the near-term resource adequacy, NS Power will implement the following strategies:

- Lingan 2 will continue to be available in cold reserve, recallable to service as needed, as discussed in **Section 3.2.3.**

[50] NS Power 2024 Load Forecast, M11689, April 30, 2024

- NS Power will continue to examine opportunities for near-term firm imports from Newfoundland across the Maritime Link.
- NS Power will position its thermal fleet for high reliability operation in Winter 2024/2025

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

Load and Resources Outlook for NS Power - Winter 2024/2025 to 2033/2034

(All values in MW except as noted)

		2024/2025	**2025/2026**	**2026/2027**	**2027/2028**	**2028/2029**	**2029/2030**	**2030/2031**	**2031/2032**	**2032/2033**	**2033/2034**
A	Firm Peak including effects of DSM & DR	2,259	2,267	2,265	2,283	2,306	2,360	2,397	2,438	2,485	2,542
B	Required Reserve (A x 20%)	452	453	453	457	461	472	479	488	497	508
C	Required Capacity (A + B)	2,711	2,720	2,718	2,739	2,767	2,833	2,876	2,925	2,982	3,051
D	Existing Resources (NS Power and IPPs)	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551	2,551
E	Existing Resources (Wholesale Market Resources)	4	4	4	4	4	4	4	4	4	4
F	Total Existing Resources (D + E)	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555	2,555
	Firm Resource Additions:										
G	Biomass	43									
H	Hydro	-101	101								
I	Tidal	1.0									
J	New Wind - Rate Base Procurement			30.6							
K	New Wind - Green Choice					33.3					
L	Port Hawkesbury Paper Wind			16.8							
M	New Wind – Future Procurement Rounds							24	12	12	12
N	New Wind – Renewable to Retail		9.0	5.9							
O	Additions - Coal to Gas Conversion					150					
P	Additions - New Gas CTs				300		300				
Q	Additions - Battery		72	24	49		36				
R	Additions - Coal to HFO Operation						459				
S	Diversity Credit			3	3	3	3				
T	Retirements				-298	-150	-781				
U	Total Annual Firm Additions (Sum of rows G thru T)	-57	182	80	54	36	17	24	12	12	12

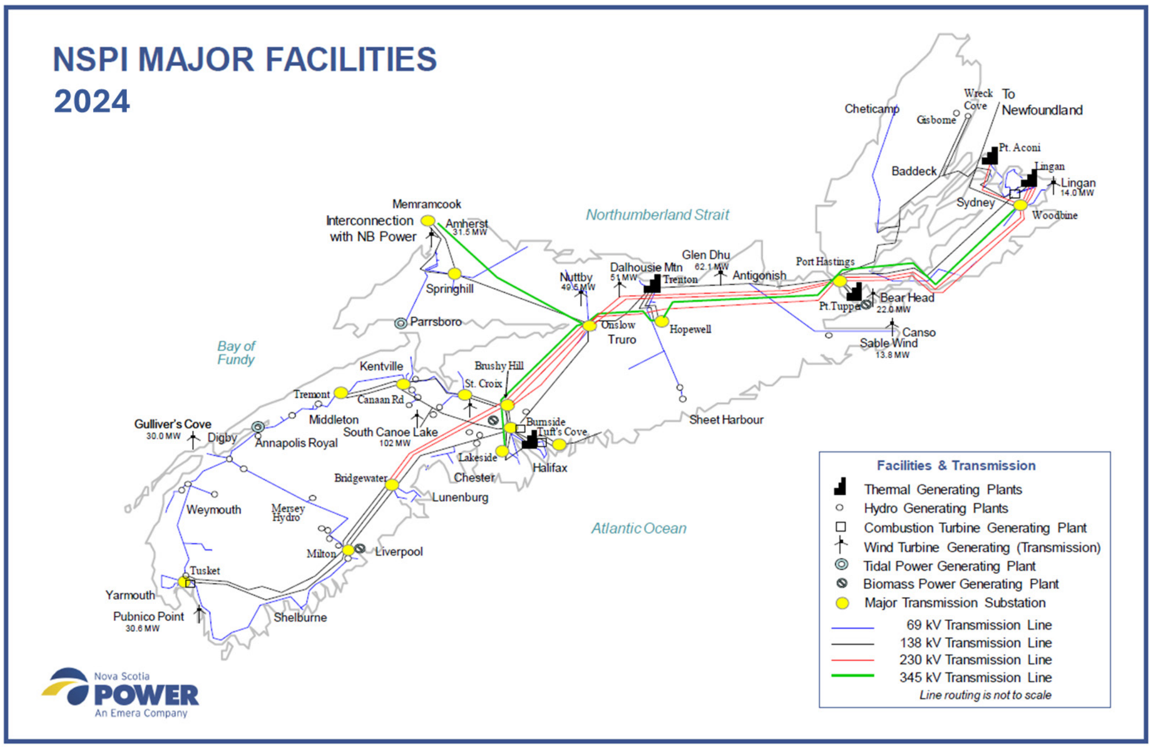
Load and Resources Outlook for NS Power - Winter 2024/2025 to 2033/2034 (All values in MW except as noted)											
		2024/2025	**2025/2026**	**2026/2027**	**2027/2028**	**2028/2029**	**2029/2030**	**2030/2031**	**2031/2032**	**2032/2033**	**2033/2034**
V	Total Cumulative Firm Additions (U + V of the previous year)	-57	125	205	259	295	312	336	348	360	372
W	Total Firm Capacity (F + V)	2,498	2,680	2,760	2,814	2,850	2,867	2,891	2,903	2,915	2,927
	+ Surplus / - Deficit (W - C)	-213	-40	42	75	83	34	15	-22	-67	-124
	Reserve Margin % [(W - A)/A]	11%	18%	22%	23%	24%	21%	21%	19%	17%	15%

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 2024



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

7.2.3 2023 Bulk Electric System Exception Requests

Since the filing of the 2023 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.

7.2.5 NPCC Directory 1 Review

A Working Group under the NPCC Task Forces on Coordination of Planning (TFCP) and Coordination of Operation (TFCO) is presently completing a review of the NPCC Directory 1 Document: Design and Operation of the Bulk Power System. 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 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. NS Power has representation from both Operations and Planning on the Directory 1 Working Group that is performing the review. Voting by NPCC members on the updates proposed by the Directory 1 Working Group is scheduled to conclude on June 27, 2024.

7.2.6 NPCC Directory 7 Review

A Working Group under the NPCC TFCP and TFCO has initiated a 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 Planning on the Directory 7 Working Group that is performing the review. The Directory 7 Working Group anticipates the review will be complete in Q3 2024.

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, 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 2023 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, 2023, twenty-four (24) Preliminary Assessments were performed in the range of 1-11 MVA, leading to the completion of five (5) 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, two (2) formal Load Impact Studies (LIS) on the transmission system were completed; five (5) transmission LIS are in progress; two (2) transmission Facilities Studies were completed, two (2) transmission Facilities Studies are in progress, and one (1) Interconnection Agreement is in progress. Projects range from 10 MW to 900 MW.

7.5 Reliability Tie

The Reliability Tie is a second 345 kV AC transmission line between Onslow, NS and Salisbury, NB. It will improve the reliability of Nova Scotia's transmission link to the New Brunswick Power system and the broader Eastern Interconnection, enabling the integration of additional variable renewable generation on the Nova Scotia system. The Reliability Tie is not anticipated to provide incremental access to firm capacity or energy.

NS Power is developing the Reliability Tie in collaboration with NB Power with a target in-service date of 2028.

The development of the Reliability Tie is in alignment with the findings of the 2020 IRP and the 2023 Evergreen IRP update enabling increased integration of variable renewable generation. NS Power provides updates on the Reliability Tie in its IRP Action Plan Updates. Progressing the Reliability Tie also facilitates future expanded Regional Interconnections to electricity systems beyond Nova Scotia, including a potential extension to Point Lepreau, NB.

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 included the assessment of the following four options:

- Option #1 - Restore L-5531, L-5532, L-5535, and L-5541 to 50ºC Temperature Rating
- Option #2 - Upgrade L-5531, L-5532, L-5535, and L-5541 to 80ºC Temperature Rating
- Option #3 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 336 ACSR Linnet and 100ºC Temperature rating
- Option #4 - Rebuild L-5531, L-5532, L-5535, and L-5541 with 556 ACSR Dove and 100ºC Temperature rating (Operate at 69 kV)

A fifth and sixth option were subsequently added in 2021 and 2022 respectively to assess bypassing the existing 69 kV infrastructure with either a single 138 kV circuit, or 138 kV double circuit construction.

- Option #5 - Bypass L-5025, L-5026, L-5531, and L-5535 with a new 138 kV line from 51V Tremont to new substations at 13V-Gulch and 9W-Tusket 16
- Option #6 - Bypass L-5025, L-5026, L-5531, and L-5535 with new double circuit 138 kV line from 51V-Tremont to new substations at 13V-Gulch and 9W-Tusket.

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) the Green Choice Procurement (GCP) of renewable generation; these studies include the addition of IPP renewable generation projects in the Valley and Western regions.

Work on the Western study will proceed following completion of these interconnection studies. Study cases will be updated to reflect 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 the study is expected to resume by Q4 of 2024.

7.7 Hydrogen Load Impact Studies

As noted in Section 7.5, 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 1024 MW of renewable generation (wind) with future requests anticipated to exceed 700MW including potential behind the meter connections (wind, solar, and BESS).

NS Power is conducting Load Impact Studies and System Impact Studies for these projects based on the assumption that the operation of the hydrogen/ammonia plants will be scheduled by the customer based on scheduled generation output of their associated generation resources. Under certain conditions, some combination of Top-up and Spill may also be permitted.

7.8 EMT Studies to Support Wind Integration

Nova Scotia Power, in collaboration with Manitoba Hydro International (MHI), completed the initial findings and recommendations report of the Large Scale Integration of Inverter Based Resources in Nova Scotia study. One of the findings is that Nova Scotia 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. There will be technical challenges and the grid will need significant support as many legacy plants are phased out or converted to alternate fuels. That said, it is achievable with the existing and evolving technologies.

The following recommendations were included in the Large Scale Integration of Inverter Based Resources in Nova Scotia report:

- Specific PSS®E and PSCAD™ model requirements were developed and have been published for all generation connecting to the Nova Scotia Power system through the Generation Interconnection Procedure (GIP). A model quality testing document was also developed which lists the minimum performance required as validation for the submitted models.

- A full grid study in PSS®E and PSCAD™ will be conducted for each round of new IBRs to be added to the Nova Scotia Power grid to identify transitory conditions or operational challenges. Confirmed in-service changes to the system, thermal unit retirements, and updated load forecast will be considered. As part of these studies, all system operating guidelines will need to be reviewed and the need for additional system support to accommodate the new IBRs will be determined.

7.9 NSPI System Inertia and Strength

Conventional synchronous machine-based power generation supplies both active power and reactive power, resulting in a high Short Circuit MVA (SCMVA) levels in most areas. SCMVA is 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 acts 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 the frequency deviations can be well damped and RoCoF managed to allow the system load and generation to remain online, system stability will be maintained. Based on the PSS®E study to date, there are concerns for the ability of the existing and future generation fleet to ride through high RoCoF events.

The network response under high RoCoF conditions will be verified through EMT simulations in PSCAD^{TM}. It should be noted that when NSPI stays connected to the Eastern interconnection, the RoCoF will be low. When the second NS/NB tie is in service, the RoCoF constraint will be removed. For the short timelines associated with a forced or maintenance outage for a NS/NB tie line, out of merit dispatch of hydro and fast acting generation in Nova Scotia is expected to mitigate potential grid restrictions.

7.9.2 System Strength

Without additional equipment, IBR resources can typically supply 10 to 20 percent of SCMVA compared to a similar sized synchronous unit. As IBRs make up a greater percentage of the generation mix, there will be a need to replace the required SCMVA and system stabilizing characteristics provided by synchronous machines.

IBRs can be used to support a grid Short Circuit Levels but additional equipment (synchronous condensers, Static Var Compensator (SVC)s or other fast acting reactive power sources) may have to be installed to support the voltage in local regions as there are some challenges with using numerous IBR units to manage System Strength. This requirement will continue to be analyzed as part of SIS and other grid studies.

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 NSUARB. 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 NSUARB. 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 nearing completion and is expected to enter service in Q2 of 2024.
2. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton. Construction on the new 98N-Stellarton substation has begun with an expected completion date of Q4, 2025.
3. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow. Area load continues to be monitored to determine the appropriate timing of this installation.

4. Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Susie Lake Crescent in 2024/25. NS Power is working with Nova Scotia Department of Public Works to acquire their property for the 142H-Susie Lake substation site.
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 in 2024. The Facility Study for the mine is currently underway.

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 NSUARB, 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. NS Power now plans to procure long lead time materials required throughout the design packages as execution is planned for 2025.

8.3 Transmission Development Plans

Transmission development plans are summarized below. As noted, these projects are subject to change. For 2024, most of the projects listed are included in NS Power's 2024 ACE Plan. As a result of the growth in the 2024 load forecast, and as coal phase-out planning continues to advance and replacement resources are identified, additional projects are anticipated to be identified.

2024

- 5P 25 MVA Mobile Substation Replacement (519754).

- Completion of 101W-Port Mersey Expansion in Q2 to include a new 138 kV-25 kV, 15/20/25 21 MVA transformer and two feeders (C0011261).
- 78W-Martins Brook substation relocation and transformer replacement (C0010956).
- Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 8 of 8).
- 76V-T51 transformer replacement with a new 5 MVA, 69 kV-13.2 kV transformer.
- Development of a new substation connection in Mt Uniacke at L-6051.

2025

- Construct new 138 kV–25 kV, 25/33/42 MVA Mt. Uniacke Substation 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 (C0021149).
- Replace existing 50/66.7/83.3 MVA 138 kV-69 kV Tufts Cove auto-transformer with a similarly rated unit (deteriorated tap changer issues).
- Replace VG Hospital transformer 10H-T41 (C005553).

2026

- Re-align L-6038 transmission structures on approach to the 129H-Kearney Lake Substation (C0061743).
- 129H-Kearney Lake Substation rebuild (C0061883).
- Construct new 25/33/42 MVA 138 kV-25 kV Susie Lake Substation complete with four 25 kV distribution feeders (C0032382).
- Construct new 15/20/25 MVA 138 kV-25 kV 113W-Cookeville (Bridgewater) Substation complete with two 25 kV distribution feeders.
- Replace 83V-Wolfville Ridge transformer 83V-T51 with a 138/69 kV-25 kV, 15/20/25 4 MVA transformer.

- Add a second 15/20/25 MVA 69 kV-12.5 kV transformer at 70W-High Street (Bridgewater). Retire the 69 kV-4.16 kV transformer 70W-T51 and install a 2.5 MVA 12.5 kV-4.16 kV padmount transformer to pick up the remaining 4.16 kV load.
- Replace 93V-Saulnierville transformer 93V-T51 with a 138/69 kV-25 kV, 15/20/25 MVA transformer.
- Add a second 25/33/42 MVA, 138 kV-25 kV transformer at the 4C substation (Lochaber 8 Road) in Antigonish.
- Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow.
- Replace existing 3/4/4.48 MVA Lower East Pubnico transformer with 7.5/10/12.5 MVA 25 unit.
- Replace VG Hospital transformer 10H-T42

2027

- 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 PHP.

2028

- Construct new 138 kV–25 kV, 25/33/42 MVA 127H-Fall River Substation complete with three 25 kV distribution feeders.

2029-2034

- There are currently no completed planning studies with transmission recommendations beyond 2029, but NS Power anticipates that more projects will be identified as coal-fired generation is phased out and electrification advances. 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.
- Installation of a fourth feeder at 126H-Porter's Lake Substation.
- Installation of a fourth feeder and replacement of the substation transformer at 127H Aerotech Park Substation.
- Replace existing 7.5/10//11.2 MVA 36V-Hillaton transformer with 15/20/25 MVA unit.

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 Evergreen IRP process reflects NS Power's commitment to continuously refining the IRP Action Plan and Roadmap items to reflect changes in the planning environment. The Province's Clean Power Plan, NS Power's The Path to 2030, and scenario CE1-E1-R2 from the Evergreen IRP modeling work form the planning basis for the 2024 10-Year System Outlook and reflect the current system planning environment at the time of this filing.