Nova Scotia Utility and Review Board

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

2022 10-Year System Outlook

NS Power

June 30, 2022

NON-CONFIDENTIAL

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1.0 INTRODUCTION

Delivering clean, reliable, and affordable energy is NS Power's commitment to customers. NS Power is working towards supplying 80 percent clean energy by 2030, and has made great strides towards that goal by more than tripling the amount of renewable energy on the grid over the last decade. In order to achieve its commitment to customers, NS Power performs planning and resource adequacy assessments while adhering to the Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

In accordance with the 3.4.2.1[1] Market Rule requirements, this report provides the 10-Year System Outlook on behalf of the Nova Scotia Power System Operator (NSPSO) for 2022. 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 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.
- A summary of generation expansion anticipated for facilities owned by NS Power and others in Section 3. 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)."

- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in Section 5. Section 5 also includes projections of the level of renewable energy available and discusses anticipated policy changes.
- A Resource Adequacy Assessment in Section 6.
- A discussion of transmission planning considerations in Section 7.

NS Power's most recent Integrated Resource Plan (IRP), undertaken in 2020, evaluated a robust set of future planning scenarios, with modeling assumptions that were created by incorporating significant stakeholder input. A reference plan (2.0C) was selected based on the lowest 25-year net present value revenue requirement (NPVRR), while meeting anticipated carbon policy and consistent with the then-current load and demand forecast (low electrification). Since the completion of the 2020 IRP and due to changes in the load forecast (Section 2) and environmental policy (Section 5), for the purposes of preparing this year's resource adequacy assessment, NS Power's modeling is more closely aligned with the IRP Scenario 3.1C which better reflects the current load and policy landscape. In accordance with NS Power's IRP Action Plan Update[2] and 2022 Evergreen IRP Study Scope and Timeline,[3] in 2022 NS Power will complete a focused evaluation and refinement of the long-term electricity strategy[4] developed as part of the 2020 IRP that reflects the current planning environment. The results of this 2022 evergreen work will inform future 10-Year System Outlook reports, as applicable.

[2] M10504, Nova Scotia Power IRP Action Plan Update, January 21, 2022.
[3] M10504, Nova Scotia Power IRP Evergreen Study Scope. April 6, 2022.
[4] M10504, Nova Scotia Power IRP Action Plan Roadmap.

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 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 2022 Load Forecast Report on April 29, 2022 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 2021 Load Forecast, the 2022 Load Forecast shows higher growth in the near term due to greater customer growth and higher average use when adjusted for weather in 2021. Mid to long-term growth is driven by a combination of increased expectations for electric heating in both the residential and commercial classes, higher electric vehicle (EV) sales driven by the Province of Nova Scotia's goal of achieving 30 percent zero-emissions vehicle sales by 2030 and the federal target of 100 percent of vehicle sales being EVs by 2035, as well as increased large customer sales driven by several large hospital expansions within the province. 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 small scale solar installations. The net result is a forecast annual average increase to NSR of 0.3 percent.

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

Year	NSR (GWh)	Growth (%)
2012	10,475	-12.0
2013	11,194	6.9
2014	11,037	-1.4
2015	11,099	0.6
2016	10,809	-2.6
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*	11,144	2.2
2023*	11,163	0.2
2024*	11,240	0.7
2025*	11,265	0.2
2026*	11,298	0.3
2027*	11,319	0.2
2028*	11,366	0.4
2029*	11,363	0.0
2030*	11,371	0.1
2031*	11,414	0.4
2032*	11,519	0.9

*Forecast value

NS Power also forecasts the peak hourly demand for future years. The total 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 total system peak 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 Capacity (ELCC) as outlined in the 2020 IRP and including critical peak pricing and direct control components, are included in the firm peak. Customer growth and increased residential and commercial electric heating increase the peak, while DSM activities reduce the peak. As a result, the system peak demand is expected to increase at an average of 1.6 percent annually over the forecast period. **Figure 2** shows the historical and forecast net system peak.

Figure 2: Coincident Peak Demand with Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	System Peak (MW)	Growth (%)
2012	141	-	1,740	1,882	-13.2
2013	136	-	1,897	2,033	8.0
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*	144	-	2,021	2,165	10.0
2023*	146	-4	2,035	2,185	0.9
2024*	146	-12	2,057	2,215	1.4
2025*	152	-24	2,076	2,253	1.7
2026*	154	-36	2,101	2,291	1.7
2027*	153	-39	2,133	2,326	1.5
2028*	153	-39	2,170	2,361	1.5
2029*	153	-39	2,207	2,398	1.6
2030*	152	-38	2,243	2,434	1.5
2031*	152	-38	2,289	2,479	1.9
2032*	152	-37	2,342	2,532	2.1

*Forecast value

As with any forecast, there is 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, the health of the economy, government policy regarding decarbonization, the impact and pace of anticipated 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 NS Power/NB Power intertie and the Maritime Link. 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) while their energy output is displaced by renewable resources when they are producing energy. 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 19**. The firm generating capability for the wholesale market participants is set out in **Figure 4.**

Figure 3: 2022 Firm Generating Capability for NS Power and IPPs

Plant/System	Fuel Type	Winter Net Capacity (MW)[5]
Avon	Hydro	6.4
Black River	Hydro	21.4
Lequille System	Hydro	23.0
Bear River System	Hydro	35.5

[5] 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)[5]
Tusket	Hydro	2.3
Mersey System	Hydro	40.4
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
Maritime Link NS Block	Hydro	153
Total Hydro		**507.9**
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[8]	Independent Power Producers (IPPs)	1.4
Post-2001 Renewables (firm)	IPPs	65.4
NS Power wind (firm)	Wind	14.5
Community-Feed-in-Tariff (firm)[9]	IPPs	30.1

[6] Annapolis is assumed to be out of service. Please refer to Section 3.2.5.
[7] Lingan Unit 2 will be available to provide firm capacity for the upcoming winter (2022/2023). Please refer to Section 3.2.4.
[8] Brooklyn Power is considered a Pre-2001 IPP, however it is not included in Figure 3 due to the outage described in Section 3.2.3.
[9] 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 6.3.1.

Plant/System	Fuel Type	Winter Net Capacity (MW)[5]
Solar	Solar	0.1
Tidal	Tidal	0.1
Total IPPs & Renewables		**111.7**
Total Capacity		**2541.6**

Figure 4: Firm Generating Capability for Wholesale Market Participants

Wholesale Market Participant	Fuel Type	Winter Net Capacity [10] (MW)
Backup Top-Up (BUTU)[11]	Wind [Ellershouse[12]]	4.2
Backup Top-Up (BUTU)	Import Contract[13]	0
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*[14] 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.

[10] M09940, UARB Backup/Top-up Service (BUTU) decision to use 18 percent ELCC for wind and 0 percent for non-firm Imports to align with current NS Power planning practices (page 38).
[11] Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.
[12] Ellershouse wind farm owned by Alternative Resource Energy Authority (AREA).
[13] Import energy contract is currently delivered via the Nova Scotia/New Brunswick Intertie.
[14] https://www.nerc.com/pa/Stand/Pages/Project2007-09-Generator-Verification.aspx

The Net Operating Capacity of the thermal units and large hydro units covered by the NERC criteria do not require adjustments at this point. NS Power will continue to refresh unit maximum capacities in the 10-Year System Outlook each year as operational conditions change.

3.1.2 Mersey Hydro

NS Power continues to assess options to address current concerns on the Mersey Hydro System. Degradation of the powerhouses and water control structures after nearly a century of service has necessitated the need for significant redevelopment work. The Mersey Hydro System is an important part of NS Power's hydro assets and is responsible for approximately 25 percent of annual domestic hydroelectric production. The Company is continuing to plan the redevelopment of the first phase of Mersey Hydro System, which is anticipated to include the replacement of the Big Falls Powerhouse, the Big Falls Control Structure and the redevelopment of the Big Falls Substation.

The 2020 IRP completed an analysis on redeveloping the Mersey system:[15]

> The Mersey Hydro system was analyzed during the Resource Screening phase of the IRP (described in Section 3.1.2) and economically retained, based on the assumptions developed from Nova Scotia Power's Hydro Asset Study (HAS). This resulted in the Mersey system being modeled as retained in all IRP key scenarios and sensitivities. However, due to the significant costs associated with redeveloping the Mersey system (as described in the HAS), IRP participants expressed a desire to examine the Mersey system specifically via a PLEXOS sensitivity.
>
> The results of this sensitivity indicate that redevelopment of the Mersey system is economic relative to decommissioning when comparing the 25-year NPVRR with end effects. The sensitivity is shown to be equivalent to the base case in terms of relative rate impact, while the decommissioning sensitivity has indicated a lower cost under the shorter NPVRR metrics (25-year without end effects and 10-year NPVRR). Nova Scotia Power notes that these are very close results in all cases, particularly for a long-lived hydro asset like the Mersey system; accordingly, additional economic analysis will be provided in any capital applications for Mersey system redevelopment.

[15] M08929, NS Power Integrated Resource Planning (IRP) Report, November 30, 2020, page 101.

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, the two 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. Model testing of the newly designed turbine runners was successfully completed in 2021 and manufacturing of the first runner is nearly complete. In 2022, NS Power has started work on the Life Extension & Modernization (LEM) Project for the Wreck Cove Generating station, with the first unit rehabilitation work beginning in June.

3.2 Changes in Capacity

3.2.1 2020 IRP

The 2020 IRP evaluated resource plans that integrate more renewable energy and reflect a provincial decarbonization strategy over the next 25 years.[16] The 2020 IRP serves as a directional roadmap to guide future decision making; it is not prescriptive in nature. The 2020 IRP Reference Plan (2.0C) outlines changes to the resource mix that are representative of many common elements in the resource plans evaluated. This plan was developed using a Low Electrification load forecast input, along with the assumption that coal generation would be retired by 2040 (or earlier as economically optimized), based on then-current assumptions. The IRP Mid Electrification resource plan with coal plant retirements by 2030 (Scenario 3.1C) is more closely aligned with the updated load forecast (described in Section 2.0) and updated environmental policy measures

[16] M08929, NS Power Integrated Resource Planning (IRP) Report, November 30, 2020.

(described in Section 5.0). The remainder of the Report uses an updated resource plan that more closely aligns with the IRP Scenario 3.1C plan rather than the IRP Reference Plan 2.0C, as Scenario 3.1C better reflects the current load forecast and updated environmental policy. The updated resource plan includes the following updated assumptions:

- Load and demand assumptions from the 2022 Load Forecast;
- 80 percent RES by 2030 as recently confirmed in the *Renewable Electricity Regulations*;
- GHG Emissions pricing using the Federal Backstop, Output-Based Pricing System (Section 5.3);
- Eastern Clean Energy Initiative (ECEI) capital investments as described in the Company's 2022 Annual Capital Expenditure (ACE) Plan (M10366); and
- The capacity and energy (2024/2025) from the Rate Base Procurement being undertaken by the Procurement Administrator appointed under the *Electricity Act*, assumed to represent 350 MW of additional wind.

Figure 5 below shows the anticipated DSM and firm capacity changes over the ten-year period starting in 2023.

Figure 5: Firm Capacity Changes & DSM

New Resources 2023-2032	Net MW
DSM Peak reduction	285
Demand Response (Firm contribution)[17]	37
Total Demand Side MW Change Projected Over Planning Period	**322**
Maintenance/Repairs:	
Hydro derates during Mersey rebuild and Wreck Cove LEM	-108
Wreck Cove LEM completion	101
Brooklyn Power (Pre-2001 IPP)	24

[17] Represents the firm contribution of demand response programs in 2032 assuming an ELCC of 48 percent. Refer to Section 2.0, Figure 2 for the annual DR totals from 2023 to 2032.

New Resources 2023-2032	Net MW
Additions:	
Firm imports over existing infrastructure	85
Biomass	43
New Wind Build (Rate Base Procurement) (Firm capacity)	35
Anticipated Firm Imports per TSR-411	550
Battery	104
Natural Gas Units	700
Point Tupper 2 Coal-to-gas conversion	150
New Wind Build (Firm capacity)	44
Retirements:	
Tufts Cove 1, 2 & 3	-318
Trenton 5 & 6	-304
Lingan 1, 2, 3 & 4	-607
Point Tupper 2	-150
Point Aconi	-168
Total Firm Supply MW Change Projected Over Planning Period	**181**

3.2.2 Evergreen Update

The evergreen IRP process represents NS Power's process for refining the Action Plan and Roadmap items to reflect changes in the planning environment (per Roadmap Item 8, which was an outcome of the 2020 IRP). The evergreen modeling is intended to confirm alignment between NS Power's electricity strategy and the current planning and policy environment. In 2022, the policy changes and changes to key drivers/inputs are significant enough when compared to the 2020 IRP assumptions that they warrant additional modeling work, targeted for completion by the end of 2022. NS Power released a 2020 IRP Action Plan Update on January 21, 2022.

On April 6, 2022 NS Power held a workshop to discuss the Action Plan and Road Map updates and discuss planning for the 2022 evergreen process. On April 2, 2022 NS Power issued a revised

IRP Action Update, reflecting new information between the original issuance date and the workshop. On April 29, 2022 NS Power released a 2022 Evergreen IRP Study Scope outline and timeline. Draft Assumptions and Scenarios were released on June 20, 2022 and a stakeholder workshop followed on June 27, 2022.

Objectives:[18]

- Complete a focused evaluation and refinement of the long-term electricity strategy developed as part of the 2020 IRP that reflects the current planning environment
- Provide a venue for stakeholder consultation and engagement in NS Power's resource planning as part of the evergreen work

Purpose:[19]

- Assess the 2020 IRP Action Plan/Roadmap based on recent policy changes
- Update the IRP Action Plan and Roadmap items as required based on the outcome of the analysis

3.2.3 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. NS Power is forecasting that the facility will return to service in the winter of 2023/2024.

3.2.4 Lingan Unit 2

Effective August 15, 2022, Lingan Unit 2 will be laid up and not made available for economic dispatch. The unit will be placed into cold reserve and available to be recalled on 2 weeks' notice.

[18] M10504, NS Power Integrated Resource Plan - Action Plan Update.

Due to the recent (February 2022) forced outage at Brooklyn Power (Section 3.2.3), coupled with the Wreck Cove LEM project scheduled outages and ongoing commissioning work on the Labrador Island Link, Lingan Unit 2 will be available, if needed, to provide firm capacity and maintain an adequate planning reserve margin (Section 6.2) for the upcoming winter (2022/2023).

In NS Power's Wreck Cove LEM capital application,[19] the single-unit winter outages were identified as requiring an offsetting capacity replacement. At the time of the application, NS Power estimated the costs of replacement capacity and included this cost in its LEM project application. As discussed in the 2021 IRP Action Update, near-term firm import opportunities over existing transmission interfaces are unavailable for winter 2022/2023. With Lingan Unit 2 phased out of economic dispatch for energy provision but available to provide firm capacity for winter 2022/2023 (recallable on 2 weeks' notice) NS Power maintains sufficient capacity to meet its planning reserve margin requirements.

3.2.5 Annapolis Tidal

Following the failure of a critical component of the Annapolis Tidal Generating Station, NS Power has determined that the facility should be retired. In February 2021, NS Power applied to the NSUARB[20] for approval of the accounting treatment of the unrecovered net book value of the assets. On January 14, 2022 the NSUARB concluded that it was not yet in a position to make a determination on the accounting treatment and would hold the application in abeyance. The NSUARB suggested the Company resubmit its application for accounting treatment along with a decommissioning application. NS Power is continuing discussions with Fisheries and Oceans Canada (DFO) and engaging in capital planning activities based on communication from the NSUARB and in support of resubmitting the application at a future date. For the purposes of the 2022 10-Year System Outlook, NS Power has assumed no capacity or energy contribution from the Annapolis Tidal Generating Station.

[19] M09596, NS Power Wreck Cove Life Extension and Modernization – Unit Rehabilitation and Replacement, CI 13838, February 28, 2020.

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

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. A summary of the anticipated system additions and retirements is set out below in **Figure 6**.

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

Winter	Additions	Retirements
2022/2023		
2023/2024	• Firm import opportunities on existing transmission infrastructure (85 MW) • New wind additions (Rate Base Procurement[21]) (Installed capacity 100 MW, firm 10 MW based on marginal ELCC of 10%)	Lingan 2 (-148 MW)
2024/2025	• Battery 200 MW (ELCC 104 MW) • New wind additions (Rate Base Procurement[21]) (Installed capacity 250 MW, firm 25 MW based on marginal ELCC of 10%) • New wind additions (Installed capacity 160 MW, firm 16 MW based on marginal ELCC of 10%) • Point Tupper 2 coal-to-gas conversation (150 MW)	Point Tupper 2 & Trenton 5 (- 300 MW)
2025/2026	• Combustion turbines (150 MW)	Tufts Cove 1 & 2 (- 171 MW)
2026/2027	• Combustion turbines (50 MW) • New wind additions (Installed capacity 100 MW, firm 10 MW based on marginal ELCC of 10%)	

[21] Nova Scotia Rate Based Procurement (novascotiarbp.com)

Winter	Additions	Retirements
2027/2028	• Combustion turbines (200 MW)	Tufts Cove 3 (- 147 MW)[22]
2028/2029	• Combustion turbines (250 MW) • New wind additions (Installed capacity 175 MW, firm 17.5 MW based on marginal ELCC of 10%)[23]	Lingan 1 & 3 (- 306 MW)
2029/2030	• Anticipated firm imports per TSR-411 (550 MW)	Trenton 6, Lingan 4, Point Aconi (- 475 MW)
2030/2031	• Combustion turbines (50 MW)	
2031/2032		

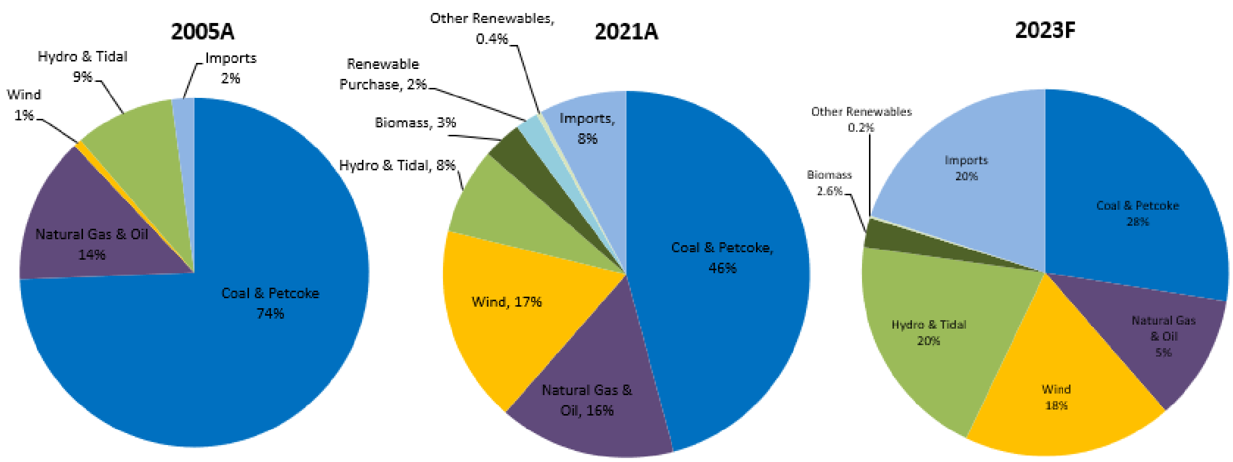
Since many of the resource additions listed are currently in the development stage, adjustments in timing for planned in-service dates and corresponding retirement dates are possible. NS Power will continue to make adjustments as required.

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 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 Sections 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 2021 and the updated forecast for 2023.

[22] Tufts Cove 1, 2 & 3 retirements were selected economically based on the 2020 IRP in favour of new gas CT capacity. The Evergreen IRP (Section 3.2.2) will further examine the economics of these retirements.
[23] See Section 6.3 for more on ELCC of new wind; verification of wind integration strategies via additional system studies will be completed as part of the IRP Action Plan.

Figure 7: 2005, 2021 Actual and 2023 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

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Lingan 1	Capacity Factor (%)	59	48	33	37	22	22	0	0	0	0
	Unit Cycles	< 10	< 10	10 - 25	10 - 25	< 10	< 10	0	0	0	0
	Service Hours	8271	6468	4030	4386	2465	2237	0	0	0	0
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
Lingan 3	Capacity Factor (%)	24	27	30	21	27	32	0	0	0	0
	Unit Cycles	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	0	0	0	0
	Service Hours	2680	3493	3308	2472	3097	3393	0	0	0	0

[24] See Section 3.2.4

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Lingan 4	Capacity Factor (%)	38	40	27	25	24	22	33	0	0	0
	Unit Cycles	10 – 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	0	0	0
	Service Hours	4680	5049	3010	2903	2758	2368	3651	0	0	0
Point Aconi	Capacity Factor (%)	26	24	10	4	1	3	14	0	0	0
	Unit Cycles	< 10	< 10	< 10	< 10	< 10	< 10	< 10	0	0	0
	Service Hours	2955	2891	1116	411	139	317	1305	0	0	0
Point Tupper [25]	Capacity Factor (%)	31	37	36	41	45	54	51	5	5	5
	Unit Cycles	< 10	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25
	Service Hours	3770	4647	5292	5894	5636	6793	6391	768	803	781
Trenton 5 [26]	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
Trenton 6	Capacity Factor (%)	45	46	34	34	37	47	40	0	0	0
	Unit Cycles	< 10	< 10	< 10	< 10	10 - 25	11 - 25	12 - 25	0	0	0
	Service Hours	6078	5862	3405	3577	3910	4897	4079	0	0	0
Tufts Cove 1	Capacity Factor (%)	15	13	4	0	0	0	0	0	0	0
	Unit Cycles	< 10	< 10	< 10	0	0	0	0	0	0	0
	Service Hours	1870	1613	353	0	0	0	0	0	0	0
Tufts Cove 2	Capacity Factor (%)	9	11	6	0	0	0	0	0	0	0
	Unit Cycles	25 - 50	25 - 50	25 - 50	0	0	0	0	0	0	0
	Service Hours	1413	1781	737	0	0	0	0	0	0	0
Tufts Cove 3	Capacity Factor (%)	21	28	30	38	37	0	0	0	0	0
	Unit Cycles	25 - 50	25 - 50	10 - 25	10 - 25	25 - 50	0	0	0	0	0
	Service Hours	3217	4435	3912	4602	3889	0	0	0	0	0

[25] Point Tupper is converted to Natural Gas for the winter of 2024/2025.
[26] Trenton 5 has operating restrictions in place and will provide firm capacity through winter 2023/2024.

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Tufts Cove 4	Capacity Factor (%)	73	67	74	78	82	85	83	65	65	64
	Unit Cycles	50 - 100	50 - 100	50 - 100	25 - 50	25 - 50	25 - 50	50 - 100	50 - 100	50 - 100	50 - 100
	Service Hours	7220	6657	6970	7310	7419	7697	7476	6125	6180	6163
Tufts Cove 5	Capacity Factor (%)	72	73	75	77	81	83	81	60	60	61
	Unit Cycles	50 - 100	50 - 100	50 - 100	25 - 50	25 - 50	25 - 50	50 - 100	50 - 100	50 - 100	50 - 100
	Service Hours	7126	7316	7004	7113	7335	7487	7278	5635	5690	5675
Tufts Cove 6	Capacity Factor (%)	42	38	50	52	63	70	69	43	43	45
	Unit Cycles	10 - 25	10 - 25	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25	50 - 100	50 - 100	50 - 100
	Service Hours	7753	6928	7417	7510	7598	7655	7506	6331	6433	6469

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 cycles (downward and upward ramping of generating units) can stress many components (e.g. turbines, motors, breakers, and fatigue in high energy piping systems) and accelerate 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 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 re-assessed in terms of their condition and intended service as NS Power's operational data, utilization plan, asset health information, and forecasts are updated.

Figure 10: Forecast Unit Utilization Factors

Unit	UF(2022-2025)	UF(2026-2029)	UF(2030-2032)
LIN-1	High	Low	Retired
LIN-2	Off	Off	Retired
LIN-3	Medium	Low	Retired
LIN-4	Medium	Low	Retired
PHB-1	High	High	High

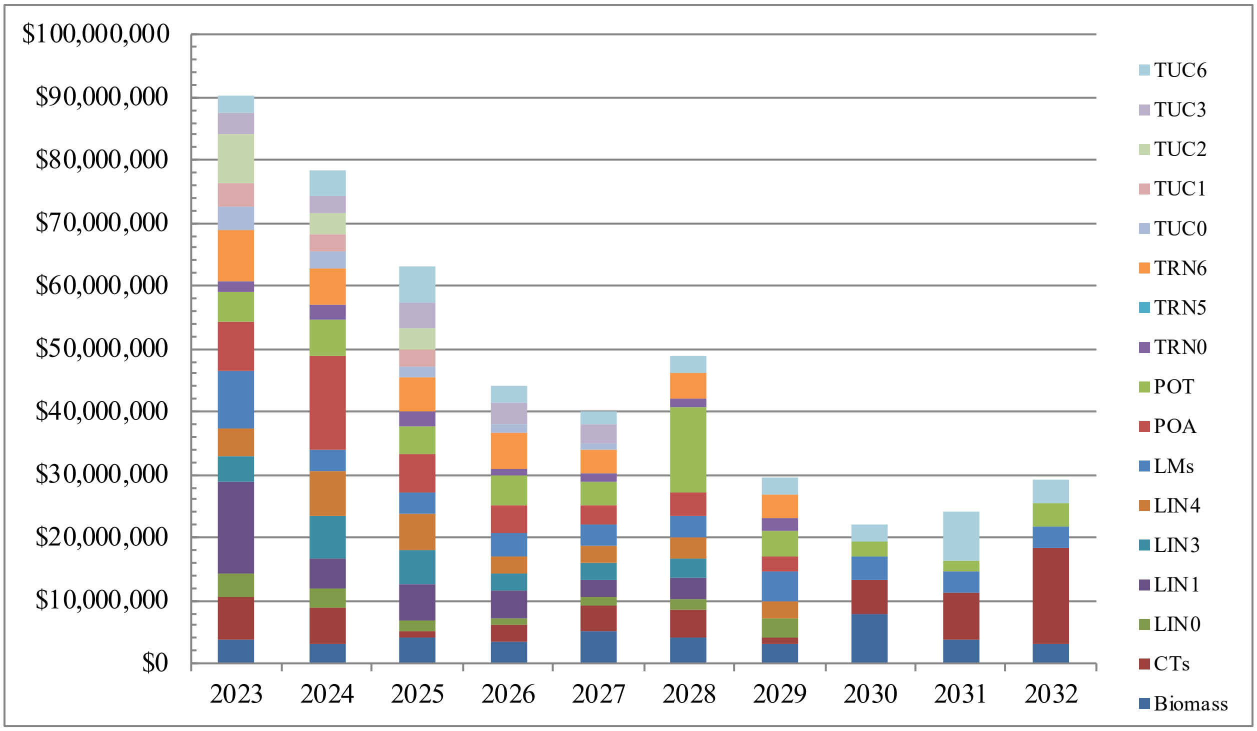
POA-1	Low	Ultra low	Retired
POT-2[27]	Medium	High	Ultra low
TRE-5	Low	Off	Retired
TRE-6	High	Medium	Retired
TUC-1	Low	Off	Retired
TUC-2	Medium	Off	Retired
TUC-3	Medium	UL/off	Retired
TUC-4	High	High	High
TUC-5	High	High	High
TUC-6	High	High	High

The overarching investment philosophy is to cost effectively maintain unit reliability 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.

The total sustaining capital forecasts in **Figure 11** are generally under the 2020 IRP sustaining capital assumptions since the utilization factors are updated with model output data versus being conservatively modeled at a high utilization factor in the 2020 IRP process.

[27] Point Tupper is converted to Natural Gas for the winter of 2024/2025.

Figure 11: Forecast Annual Investment (in 2022$) by Unit



Note: As it is used for asset planning, the figure above does not include escalation. Forecast investments are subject to change arising from asset health and actual utilization. Changes in currency value and inflation can also have significant effect on actual cost.

4.0 QUEUED SYSTEM IMPACT STUDIES

Active transmission and distribution requests not appearing in the Combined Transmission & Distribution Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage, as they have not yet proceeded to the SIS stage of the Generator Interconnection Procedures (GIP) or Distribution Generator Interconnection Procedures (DGIP). **Figure 12** below provides the location and size of the generating facilities currently in the Combined T&D Advanced Stage Interconnection Request Queue.

The Port Hawkesbury Biomass generating unit (63.8 MW gross / 45 MW net output) is presently an ERIS-classified resource which will be converted to NRIS following the system upgrades associated with Transmission Service Request 400 which is discussed further in Section 4.1.

Figure 12: Combined Transmission & Distribution Advanced Stage Interconnection Queue as of June 24, 2022

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Inter-connection Point	Type	In-Service date DD-MMM-YY[28]	Status	Service Type
1-T	426	27-Jul-12	Richmond	45.0	45.0	47C	Biomass	01-Sep-18	GIA Executed	NRIS
2-T	516	5-Dec-14	Cumberland	5.0	5.0	37N	Tidal	31-May-20	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	5.6	5.6	24H	CHP	01-Sep-18	SIS Complete	N/A
6-D	569	26-Jul-19	Digby	0.6	0.6	509V-302	Tidal	30-Jul-21	GIA Executed	N/A
7-D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	30-Apr-22	GIA Executed	N/A
8-T	574	27-Aug-20	Hants	58.8	58.8	L-6051	Wind	30-Jun-23	FAC in Progress	NRIS

[28] 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	MW Winter	Inter-connection Point	Type	In-Service date DD-MMM-YY[28]	Status	Service Type
9-T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	01-Dec-22	SIS Milestones Met	NRIS
10-D	604	7-Jun-21	Cape Breton	0.45	0.45	11S-303	Solar	15-Jan-22	GIA Executed	N/A
11 -D	603	31-May-21	Cumberland	0.4	0.4	22N-404	Solar/ Battery	16-Feb-22	GIA Executed	N/A
12-D	600	27-May-21	Halifax	0.6	0.6	99H-312	Solar/ Battery	2-Mar-22	GIA Executed	N/A
13-T	597	7-May-21	Lunenburg	33.6	33.6	50W	Wind	31-Aug-23	SIS in progress	NRIS
14-T	629	20-Sep-21	Cumberland	0.5	0.5	7N	Solar	28-Sep-21	SIS in progress	ERIS
15-T	647	6-Oct-21	Cumberland	1.5	1.5	37N	Tidal	31-Dec-23	SIS in progress	NRIS
16-D	653	19-Jan-22	Halifax	0.09	0.09	24H-406	Solar	30-Oct-22	SIS in progress	N/A
17-D	654	16-Feb-22	Halifax	0.125	0.125	127H-413	Solar	20-Sep-22	SIS in progress	N/A

4.1 OATT Transmission Service Queue

As of June 8, 2022 there are two active requests in the OATT Transmission Queue as shown in **Figure 13**.

Figure 13: Requests in the OATT Transmission Queue

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, 2025	550	Facilities Study in Process

*Indicates project as being located near provincial border.

In its Decision on the 2020 10-Year System Outlook, the NSUARB provided the following direction with respect to the information provided about Requests in the OATT Transmission Queue:[29]

> In section 5.1 of the SO Report, Figure 8 lists the requests that are currently in the OATT transmission queue. Some of those requests are for network service while others are for point-to-point service. The Board directs that future reports include an expanded description in the column titled "Project Location" for each request.

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[30] 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. However, in an effort to be responsive to the NSUARB's direction and maintain the non-confidential nature of the Report, NS Power has provided additional information in the note to **Figure 13**.

System upgrades related to Transmission Service Request 400 now have their design complete. Execution of upgrades is planned for Q3 2022.

A Facilities Study is being performed for TSR 411.

[29] M09776, Nova Scotia Power 2020 10-Year System Outlook Report (P-194), NSUARB Letter re accepted as filed, August 28, 2020.

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

5.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

5.1 Renewable Electricity Requirements

The RES include a renewable energy requirement for NS Power of 25 percent of energy sales in 2015, and 40 percent in 2020.[31] On July 9, 2021 the Province of Nova Scotia amended the *Renewable Electricity Regulations* to add a RES of 80 percent of energy sales for 2030. NS Power was directed to meet this requirement, in part, through the acquisition of 1,100 GWh of renewable energy from independent power producers. The Province also announced on July 10, 2021 that it was initiating a procurement of 1,100 GWh of electricity from renewable sources as part of its Rate Base Procurement program. The procurement administrator is anticipated to identify the portfolio in August 2022, and the selected projects must be in service by December 31, 2025.[32]

Nova Scotia also has a Community Feed-in-Tariff (COMFIT) for projects which include community ownership that are connected to the distribution system as well as Net Metering legislation for renewable projects.[33] The current Net Metering program was initiated in July 2011, and implementation of the COMFIT program occurred in September 2011.

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.[34] 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.

[31] *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).
[32] Timeline | Nova Scotia Rate Based Procurement (novascotiarbp.com)
[33] Effective April 22, 2022, the *Electricity Act* was amended with updates to the Net Metering legislation. https://nslegislature.ca/legislative-business/bills-statutes/bills/assembly-64-session-1/bill-145.
[34] *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).

A key component of NS Power's ability to meet its 2020 RES requirements was the commencement of the operation the Muskrat Falls Hydro Generating Project and the associated delivery of renewable energy. On March 27, 2020 Nalcor Energy (Nalcor) announced that it temporarily paused construction activities at the Muskrat Falls project site in response to the COVID-19 pandemic.[35] Construction and commissioning of the Muskrat Falls hydro project subsequently resumed on May 30, 2020. Given the risk of a delay in the delivery of the Nova Scotia Block, the Nova Scotia Minister of Energy and Mines permitted NS Power to address this through an Alternative Compliance Plan for 2020 through 2022 under the RES Regulations. In part, the Minister's Alternative Compliance Plan directs NS Power to make up the shortfall by extending the compliance period for meeting the 40 percent renewable energy standard over the three calendar years 2020, 2021 and 2022.

For the years 2020 and 2021, the Company served 29 percent (2020) and 30.4 percent of sales (2021) using qualifying renewable energy sources. The Nova Scotia block began delivery on August 15, 2021. However, ongoing issues are preventing the full delivery of energy from Muskrat Falls, and the Company's ability to achieve 40 percent of total sales from renewable sources from 2020 to 2022 is at risk.

The RES Compliance Forecast in **Figure 14** illustrates the full amount of RES-eligible energy forecast to be available to the Company for 2023-2025.

Figure 14: RES Compliance Forecast

RES Compliance Forecast[36]			
	2023	**2024**	**2025**
Energy Requirements (GWh)			
NSR including DSM effects	11,162	11,240	11,461
Losses	727	732	732
Sales	10,435	10,508	10,659
RES (%) Requirement	40%	40%	40%
RES Requirement (GWh)	**4,174**	**4,203**	**4,264**

[35] https://muskratfalls.nalcorenergy.com/march-27-2020-covid-19-update-from-nalcor-on-the-muskrat-falls-project/
[36] NSR and Losses are provided in the 2022 NS Power Load Forecast Report, Table A1, April 29, 2022 (M10109).

Renewable Energy Sources (GWh)			
NS Power Wind	264	264	261
Post-2001 IPPs	770	770	2455
PH Biomass	290	290	290
COMFIT Wind Energy	523	523	534
COMFIT Non-Wind Energy	15	15	45
Eligible Pre-2001 IPPs	82	77	91
Eligible NSPI Legacy Hydro	885	896	928
REA procurement (South Canoe/Sable)	357	357	354
Compliant Renewable Import	1,134	1,134	1,134
Forecast Renewable Energy (GWh)	**4,320**	**4,326**	**6,092**
Forecast Surplus or Deficit (GWh)	**146**	**123**	**1,828**
Forecast RES Percentage of Sales	**42%**	**41%**	**57%**

5.2 Environmental Regulatory Requirements

Environmental Regulatory Requirements 2019 to 2022

The Nova Scotia *Greenhouse Gas Emissions Regulations*[37] 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. Carbon emissions in Nova Scotia from the production of electricity in 2030 are forecast to have decreased by 58 percent from 2005 levels.

Figure 15: Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes (CO_2)
2014-2016	26.32

[37] *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.

2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

The *Sustainable Development Goals Act*[38] (SDGA) stated Nova Scotia's goals to achieve province-wide greenhouse gas emission reductions of at least 10 percent below levels emitted in 1990 by 2020, at least 33 percent below the levels that were emitted in 2005 by 2030, and a "net zero" by 2050 by balancing greenhouse gas emissions with greenhouse gas removals and other offsetting measures. However, the SDGA was repealed by the *Environmental Goals and Climate Change Reduction Act* (2021) (EGCCRA), which indicates a more stringent 2030 emissions target of 53 percent below 2005 levels. Further discussion of the EGCCRA is provided in Section 5.2.

On January 1, 2019 Nova Scotia's cap-and-trade program came into effect. The *Cap-and-Trade Program Regulations* include the annual free allowances for GHG emissions for NS Power.

Under the GHG cap-and-trade system NS Power is allowed to purchase no more than 5 percent of GHG credits offered for auction by the province. NS Power is forecasting that the GHG credits available for the company to purchase will be approximately 85 kt annually. Although bilateral GHG trades among mandatory GHG cap-and-trade program participants are permitted, there has been only one bilateral trade reported to date and any liquidity in this market is likely to be slow to develop. Due to the limited quantity of GHG auction credits available for NS Power to purchase and the lack of significant GHG credits availability via bilateral trades, the compliance strategy is expected to consist of a reduction of GHG emissions though fleet dispatch and purchase of additional reserve GHG credits at the end of the compliance period.

[38] *An Act to Achieve Environmental Goals and Sustainable Prosperity*, S.N.S. 2019, c. 26, not proclaimed in force.

Although the free GHG allowance under the GHG cap-and-trade system was specified for each year from 2019 to 2022 as noted in **Figure 16**, the allowances can be redistributed in a four-year compliance period between 2019 and 2022 in order to reduce the cost of compliance. NS Power is on track to meet the requirements of the program, where compliance is forecast to be achieved through reduced emissions and credit purchases.

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

NS Power's thermal facilities that meet the CO_2 emissions threshold for cap-and-trade (50,000 tonnes) are not required to pay fuel surcharges on fuel consumed for electricity generation. Fuel consumed for on-site activities via mobile equipment is subject to a fuel surcharge under the *Cap-and-Trade Regulations*.

As the Port Hawkesbury Biomass facility and the combustion turbine sites do not meet the emissions threshold, fuel consumed on those sites is subject to fuel surcharges under the *Cap-and-Trade Regulations*.

The Nova Scotia *Air Quality Regulations*[39] specify emission caps for sulphur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg). These regulations were amended to extend from 2020

[39] *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.

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)

<table>
<tr><th>Multi-Year Caps Period</th><th>SO₂ (t)</th><th>SO₂ (t) Annual Max</th><th>NOx (t)</th><th>NOx (t) Annual Max</th><th>Hg (kg)</th></tr>
<tr><td>2020</td><td>60,900</td><td></td><td rowspan="2">14,955</td><td></td><td>35</td></tr>
<tr><td>2021-2022</td><td>90,000</td><td rowspan="2"></td><td rowspan="2">14,955</td><td>35</td></tr>
<tr><td>2023-2024</td><td>68,000</td><td>56,000</td><td>35</td></tr>
<tr><td>2025</td><td>28,000</td><td></td><td>11,500</td><td></td><td>35</td></tr>
<tr><td>2026-2029</td><td>104,000</td><td>28,000</td><td>44,000</td><td>11,500</td><td>35</td></tr>
<tr><td>2030</td><td>20,000</td><td></td><td>8,800</td><td></td><td>30</td></tr>
</table>

By 2030 SO_2 emissions from generating electricity will have been reduced by 80 percent from 2005 levels. NOx emissions will have decreased by 73 percent and mercury emissions will have decreased 71 percent from 2005 levels.

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 through to the end of January 2020. The program involved recycling light bulbs or other mercurycontaining consumer products, which reduced the amount of mercury going into the environment through landfills. Credits approved by Nova Scotia Environment and Climate Change (ECC) may be used to compensate from the deferred emissions by 2020, and a limited amount of credits approved by ECC (30 kg in 2020, 10 kg per year for subsequent years) may be used for compliance from 2020 to 2029.

Environmental Policy – 2023 to 2030

In December 2020, as part of the report titled *A Healthy Environment and a Healthy Economy*,[40] 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 in order 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. This is discussed further in Section 5.3.

As noted above, the province introduced the EGCCRA on October 27, 2021.[41] The EGCCRA references the 80 percent RES 2030 requirement in addition to the requirement to phase out coal-fired electricity generation in the Province by 2030, provincial GHG reduction targets of 53 percent below 2005 levels by 2030, Net Zero by 2050 (discussed further in Section 5.4) 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.

[40] https://www.canada.ca/en/environment-climate-change/news/2020/12/a-healthy-environment-and-a-healthy-economy.html
[41] *Environmental Goals and Climate Change Reduction Act*, S.N.S. 2021, c. 20, s. 1.

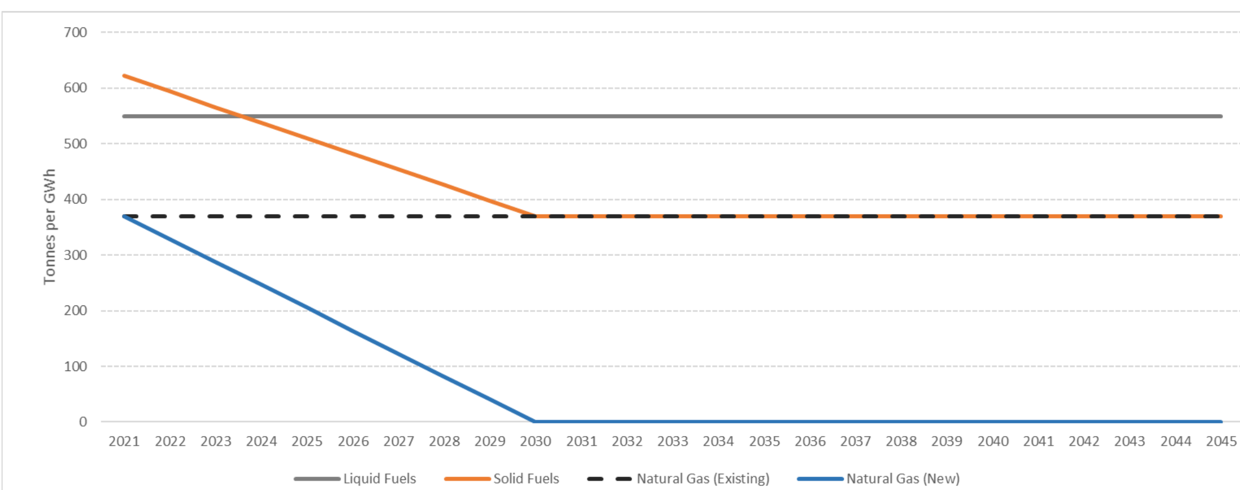
5.3 Carbon Pricing (Output-Based Pricing System)

In the absence of defined carbon policy requirements in Nova Scotia for 2023 to 2030 and beyond, for this Report NS Power has incorporated the Federal Backstop Carbon Pricing price trajectory and the associated Output-Based Pricing System (OBPS) shown in **Figure 18** as the mechanism for deriving carbon pricing signals for unit commitment and economic dispatch of NS Power's generation fleet. Please refer to Section 3.3.

The federal OBPS is designed to provide a price incentive for industrial emitters to reduce their greenhouse gas emissions and spur innovation while maintaining competitiveness and protecting against "carbon leakage" (i.e. the risk of industrial facilities moving from one region to another to avoid paying a price on carbon pollution).

The Federal OBPS sets an emissions intensity limit for each facility subject to the program (covered facilities). This emissions limit is calculated using an emissions intensity performance standard for a given activity (e.g. electricity generation by fuel type).

Figure 18: NS Power's modeling assumptions of the Federal Emission Intensity Standards (OBPS)



5.4 Anticipated Policy Changes

As discussed in the previous section, the Federal Government provided guidance on the options available to the province to establish a Provincial Carbon Policy framework as potential alternatives to the Federal Backstop. NS Power understands the province will work with Environment and Climate Change Canada to establish the Carbon Policy framework for Nova Scotia from 2023 through to 2030.

The Federal Government also produced a discussion paper on a potential Clean Electricity Standard (CES)[42] and discussed the need for CES regulations to support this under the *Canadian Environmental Protection Act* (CEPA). The focus of the discussion paper was on the Federal Government's commitment to target Net-Zero Electricity 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 parallel, the OBPS emissions performance standards will be reviewed within the context of meeting the 2035 targets and beyond. Details of the engagement period to follow have not yet been shared.

In response to both the existing and anticipated policy changes, NS Power is assessing, refining, and enabling the electricity strategy to continue on the path to meet the 2030 targets (80 percent RES, coal phase-out, carbon pricing) and beyond (net-zero electricity 2035) through the transformation of the generation fleet. This is supported by the NS Power evergreen IRP process and by refining the IRP Action Plan and Roadmap items identified as part of the 2020 IRP.

NS Power continues to engage with both levels of government to explore opportunities to accelerate the Company's carbon reduction strategy in a way that is affordable for customers, maintains reliability, and supports NS Power's customers and the communities where they live and work. As the government's announced policy changes become legislative and regulatory requirements, NS Power will reflect these changes in future planning studies.

[42] A clean electricity standard in support of a net-zero electricity sector: discussion paper - Canada.ca

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. 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.[43]

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*[44] NS Power and New Brunswick Power (NB Power) have agreed to share the reserve requirement for the Maritimes Area on the following basis:

> The Ten-Minute Reserve Responsibility, for contingencies within the Maritimes Area, will be shared between the two Parties based on a 12CP [coincident peak] Load-Ratio Share… Notwithstanding the Load-Ratio Share the maximum that either Party will be responsible for is 100 percent of its greatest, on-line, net single contingency, and, NSPI shall be responsible for 50 MW of Thirty-Minute Reserve.

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

[44] New Brunswick's Electricity Act (the Act) was proclaimed on October 1, 2013. Among other things, the Act establishes the amalgamation of the New Brunswick System Operator (NBSO) with New Brunswick Power Corporation ("NB Power").

The Ten-Minute Reserve Responsibility formula results in a reserve share of approximately 40 percent of the largest loss-of-source contingency in the Maritimes Area (limited to 10 percent of Maritimes Area coincident peak load). This yields a reserve share requirement for NS Power of approximately 40 percent of 550 MW (220 MW), capped at the largest online unit in Nova Scotia. When Point Aconi is online, NS Power maintains a ten-minute operating reserve of 168 MW (equivalent to Point Aconi maximum net output), of which approximately 32 MW[45] is held as spinning reserve on the system. Additional regulating reserve is maintained to manage the variability of customer load and generation. The reserve sharing requirement with Maritime Link as the largest source in Nova Scotia will depend on the amount of Maritime Link power used in Nova Scotia.

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*[46] 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.

[45] Spinning reserve requirement can be as high as 39 MW depending on power flows over the Maritime Link.
[46] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories

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 2020 IRP, as discussed in Section 3.2.1.

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 renewable resources.

In a letter dated October 5, 2018[48] the NSUARB directed NS Power to complete a number of 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 currently installed on the NS Power system to be 19 percent. The declining marginal ELCC value of adding new wind to the NS Power system was determined to

[47] M08929, Nova Scotia Power, IRP Final Report, November 27, 2020, page 40.
[48] M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.
[49] M08929, Integrated Resource Planning and Generation Utilization and Optimization (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/

be 11 to 9 percent. In the 2020 IRP, the Company used 10 percent for the ELCC value of new wind. 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, 10 percent capacity value of new wind, and 95 percent for hydro.

Please refer to Section 3.1 regarding the inclusion of ERIS wind resources.

Municipal load for Berwick, Mahone Bay, Antigonish, and Riverport is served by a wind farm owned by Alternative Resource Energy Authority (AREA) and by imports. 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 19** 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 current forecast indicates a small capacity deficit in Winter 2023/2024. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve, and will adjust decisions accordingly.

Figure 19 is intended to provide a medium-term outlook of the capacity resources available to the Company compared to expected customer demand, given the most recent assumptions to date. As noted in Section 6.2, the PRM provides a basis for the minimum required firm generation NS Power must maintain to comply with NPCC reliability criteria; it does not represent the optimal or maximum required capacity to serve other system requirements. In its Final Report submitted to the NSUARB in the Generation Utilization and Optimization proceeding,[50] Synapse stated:

[50] Synapse Energy Economic Inc., Nova Scotia Power Inc. Thermal Generation Utilization and Optimization Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059, filed on May 1, 2018.

> The PRMs provide one high-level measure of the amount of generation capacity relative to the NPCC 20 percent planning reserve margin requirement. PRM is defined as the amount of firm capacity available over the planning peak load. Notably, the NPCC constraint is not the only constraint that dictates how much capacity might be required on the system. Plexos' ability to model hourly dispatch requirements means that any ramping requirements must be met with adequate capacity. Also, the presence of annual emissions constraints combined with the multi-fossil-fuel environment in which the thermal fleet operates (coal, oil, gas) leads to capacity requirements that could exceed thresholds needed to meet either NPCC reserve or ramping requirements. The integrated aspect of the model (long-term planning and short-term dispatch) is intended to allow capture of all these moving parts when optimizing retirement and build decisions.[51]

As noted by Synapse, other considerations may dictate the most economic generating capacity for the system; therefore, any surplus capacity in an outlook does not necessarily suggest that any full or partial unit retirement would be possible or optimal, as these units may provide other additional value. The optimal capacity requirements, including addressing a capacity shortfall and the timing of unit retirements, have been evaluated in the 2020 IRP and will be analyzed further as NS Power updates its long-term planning analyses, including as part of the 2022 evergreen IRP update.

[51] *Ibid* at Section 3.1.

Figure 19: NS Power 10-Year Load and Resources Outlook[56]

Load and Resources Outlook for NSPI - Winter 2022/2023 to 2031/2032 (All values in MW except as noted)											
		2022/ 2023	2023/ 2024	2024/ 2025	2025/ 2026	2026/ 2027	2027/ 2028	2028/ 2029	2029/ 2030	2030/ 2031	2031/ 2032
A	Firm Peak including effects of DSM & DR [52]	2,035	2,057	2,076	2,101	2,133	2,170	2,207	2,243	2,289	2,342
B	Required Reserve (A x 20%)	407	411	415	420	427	434	441	449	458	468
C	Required Capacity (A + B)	2,442	2,468	2,491	2,521	2,560	2,604	2,648	2,692	2,747	2,810
D	Existing Resources (NS Power and IPPs)	2,542	2,542	2,542	2,542	2,542	2,542	2,542	2,542	2,542	2,542
E	Existing Resources (Wholesale Market Resources)	4	4	4	4	4	4	4	4	4	4
F	Total Existing Resources (D + E)	2,546	2,546	2,546	2,546	2,546	2,546	2,546	2,546	2,546	2,546
	Firm Resource Additions:										
G	Biomass [53]	43	24								
H	Hydro [54]	-108		101							
I	New Wind - Rate Base Procurement[55]		10	25							
J	Additions - Wind			16		10		18			
K	Additions - Coal to Gas Conversion			150							
L	Additions - New CTs				150	50	200	250		50	
M	Additions - Other		85	104					550		
N	Retirements		-148	-300	-171		-147	-306	-475		
O	Total Annual Firm Additions (G + H + I + J + K + L + M + N)	-65	-29	96	-21	60	53	-39	75	50	0
P	Total Cumulative Firm Additions (O + P of the previous year)	-65	-93	2	-19	42	95	56	131	181	181
Q	Total Firm Capacity (F + P)	2,481	2,453	2,548	2,527	2,587	2,640	2,602	2,677	2,727	2,727
	+ Surplus / - Deficit (Q - C)	39	-16	57	6	28	36	-47	-15	-20	-84
	Reserve Margin % [(Q - A)/A]	22%	19%	23%	20%	21%	22%	18%	19%	19%	16%

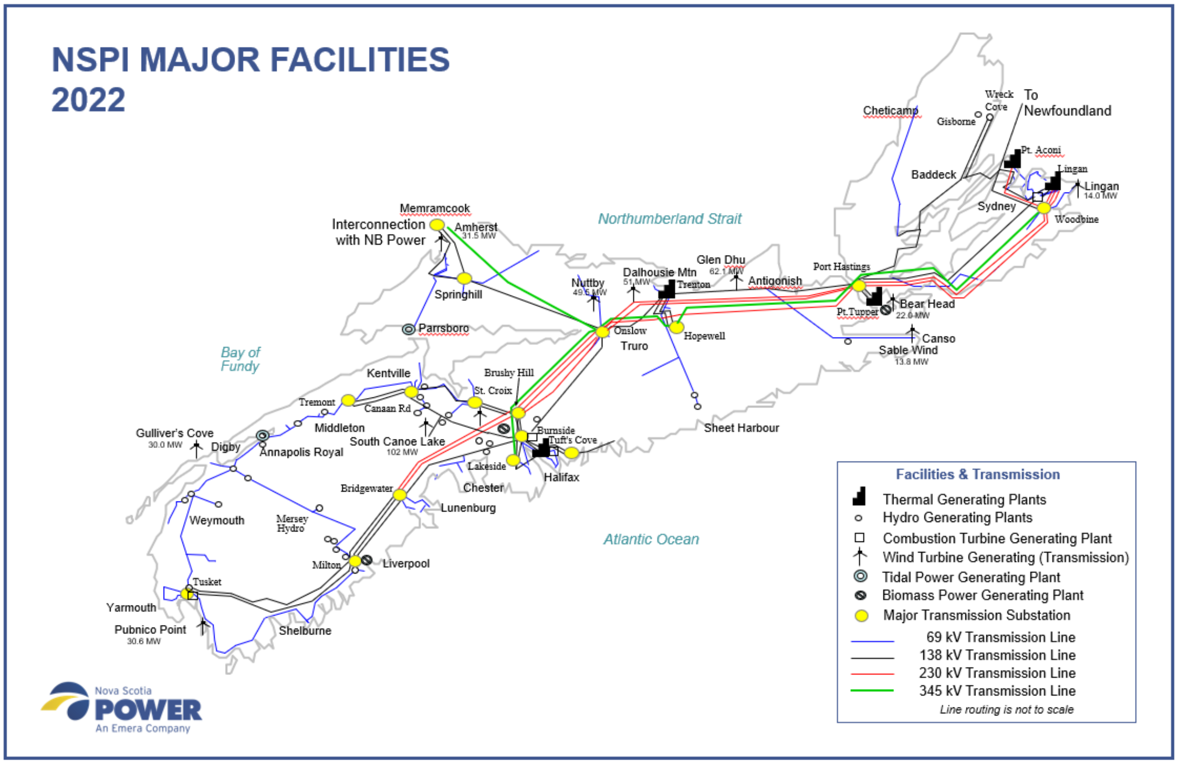
[52] 2022 Load Forecast. Firm peaks include the effects of both DSM and DR programs (DR programs as evaluated in the 2020 IRP).
[53] PH Biomass (43 MW) assumed to transfer to NRIS service in Q3 2022. NS Power is forecasting that Brooklyn Power (24 MW) will return to service in the winter of 2023/2024.
[54] Assumes ELCC of 95 percent for hydro sites. Mersey is derated by 6.8 MW during anticipated rebuild work; please refer to Section 3.1.2. Wreck Cove life extension modifications assume one unit will be unavailable from June 2022 to July 2024; please refer to Section 3.1.3.
[55] The timeline for the Rate Base Procurement can be found here: https://novascotiarbp.com/timeline. Any changes in this timeline and the makeup of the final portfolio could influence the timing of these additions.
[56] Resource additions must first demonstrate reliable performance before corresponding retirements are fully decommissioned.

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has approximately 5,220 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 20**.

Figure 20: NS Power Major Facilities in Service 2022



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.

Nova Scotia is also interconnected with Newfoundland via a 500 MW, +/-200 kV DC 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 North American Electric Reliability Corporation (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 2022 Bulk Electric System Exception Requests

Since the filing of the 202110 Year System Outlook Report, no new BES Exception Requests have been received.

7.2.4 Bulk Electric System Compliance Gaps [From Board Order M06930]

On April 6, 2017), the NSUARB ordered as follows with respect to BES compliance gaps that were identified in *Section 7-Impact Assessment and Plan for Compliance* of the NERC BES Definition Project Application to the NSUARB dated June 15, 2015:

> …IT I*S FURTHER ORDERED that NSPI's plan to address compliance gaps as described in the Application is approved and compliance work for newly identified BES elements shall be completed within five years from the date of this Order. The Board directs NSPI to include a report on the status of compliance gaps in its annual 10 Year System Outlook Report.*

The compliance gaps identified included the following:

1. Disturbance monitoring equipment required for each of the generating facilities at 14H-Burnside, 83S-Victoria Junction, and 85S-Wreck Cove.
2. Disturbance monitoring equipment required at 79N-Hopewell and 103H-Lakeside.
3. Compliance gaps identified at the 2C-Port Hastings Substation; 88S-Lingan 138kV Substation bus; the 101S-Woodbine Substation; and the 120H-SVC.

NS Power has either corrected the compliance gaps identified above or determined the compliance is no longer required based on the current BES status of the transmission bus in question:

a) 14H-Burnside and 83S-VJ:

Disturbance monitoring equipment is no longer required since the generators are not connected to BES buses.

b) 85S-Wreck Cove:

Disturbance monitoring equipment is no longer required since the generators are not connected to BES buses.

c) 79N-Hopewell and 103H-Lakeside:

Disturbance monitoring is now in service at the 101S-Woodbine 230kV bus; the 101S-Woodbine 345kV bus; and at the 120H-Brushy Hill 138kV bus. With that monitoring in place, there is no requirement for additional disturbance monitoring at 79N-Hopewell or 103H-Lakeside.

d) 2C/3C-Port Hastings:

Projects to bring the substation up to NPCC BPS compliance standards were completed in 2020. This work brought 2C/3C into compliance with BES standards also.

e) 88S-Lingan:

A project to bring the substation up to NPCC BPS compliance standards was completed in 2019. This work brought 88S into compliance with BES standards also.

f) 101S-Woodbine:

The 101S Woodbine substation is currently in service with disturbance monitoring equipment that meets the requirements of NERC PRC-002-2 at both the 230kV and 345kV voltage levels.

g) 120H-Brushy Hill SVC:

A project to bring this SVC up to NPCC BPS compliance standards was completed in 2017. This work also brought 120H-SVC into compliance with BES standards.

As a result of the work detailed above, NSPI has eliminated the outstanding compliance gaps identified in by the NSUARB within the permitted five-year time frame.

7.2.5 Special Protection Systems (SPS)

Special Protection Systems (SPS) are also referred to as Remedial Action Schemes (RAS) in NERC documentation. Both terms are valid.

NS Power makes use of SPS 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 SPS.

7.2.6 NPCC Directory 1 Review

A Working Group under the NPCC Task Forces on Coordination of Planning (TFCP) and Coordination of Operation (TFCO) is presently conducting 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[57] 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. The Directory 1 Working Group anticipates the review will be complete in Q3 2023.

7.3 Transmission Life Extension

NS Power has a comprehensive maintenance program in place for the transmission system 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:

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

- 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 Transmission Project Approval

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 on the basis of 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.

7.5 New Large-Load Customer Interconnection Requests

NS Power continued to receive large numbers of new large-load requests in 2021 with respect to proposed commercial, mining, aquaculture and government projects ranging in size from 1-15 MVA. As a result, approximately forty-one (41) Preliminary Assessments were performed, leading to the completion of ten (10) formal Load Impact Studies on both the transmission and distribution systems. In some instances, Preliminary Assessments determined that a Load Impact Study was not required. Not all these assessments translate into near-term load, as some projects have multi-year construction or are not completed.

8.0 TRANSMISSION DEVELOPMENT 2022 TO 2032

Investments in transmission infrastructure can be affected by energy policy and the changing sources of energy and capacity. Proposed transmission development plans and projects are subject to reconsideration and alignment with current policy goals. Items described below are current as of the date of this report.

8.1 Impact of Proposed Load Facilities

As noted in Section 7.5 of this Report, there are a number of system upgrades required to serve load facilities greater than 1 MW that were proposed in 2020 and 2021. These projects have 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 currently under construction with an expected completion date in 2022.
2. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in 2022/23. The design of this substation is currently in progress.
3. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow in 2023. 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 2023/24. Property acquisition for this site is currently underway.
5. Installation of a new 10MVA, 69-25kV portable dead-front transformer on line L-5510 required to provide a 25kV supply to a new mine site in 2022/23.

8.2 129H-Kearney Lake Relocation

Detailed inspection of these two land parcels revealed that site development costs would be much higher than expected in order to grade the property and provide a suitable access route into the site for a mobile transformer unit. Subsequent negotiations with the owners of the existing site resulted in a new option to swap the existing Kearney Lake Substation site (plus sufficient property to enable an expansion for a second transformer and new approach structure) with the NS Power-owned land parcels across the street. The owners of the Kearney Lake site are prepared to extend the existing lease to complete this option. This option also involves surrendering a small portion of the existing L-6038 ROW, resulting in re-alignment of the 129H transmission approaches so that L-6038 will be in the same corridor as the existing L-5004. Once complete, the existing 129H-Kearney Lake substation site will be suitable for the future addition of a second transformer. The transmission structure re-alignment is scheduled for 2023.

8.3 Transmission Development Plans

Transmission development plans are summarized below. As noted above, these projects are subject to change. For 2022 the majority of the projects listed are included in NS Power's 2022 ACE Plan. As a result of the growth in the 2022 load forecast, and as coal phase-out planning continues to advance and replacement resource are identified, additional projects are anticipated to be identified.

2022

- Completion of 5P 25 MVA Mobile Substation Replacement (carry-over from 2021).
- Completion of 101W-Port Mersey Expansion to include a new 138 kV-25 kV, 15/20/25 MVA transformer and two feeders (C0011261).
- 78W-Martins Brook substation relocation and transformer replacement (C0010956). Site purchase in 2022.
- Line structure replacements and upgrades.
- Resolution of the Aulds Cove 345kV crossing line deration (parallel existing lines vs disconnection and grounding of lower three lines).
- Replacement of 9W-B53 support structure. Not done in 2021.
- Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in 2022/23.
    - Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 6 of 8).
    - Purchase of new large spare auto-transformer (C0031050).

- Purchase of replacement spare for unit utilized at 58C-SW Margaree Substation (C0031052)
- Purchase suitable lot for establishing a new 138kV–25kV Suzie Lake Substation.
- Purchase new 138 kV–25 kV, 15 MVA Skid-Mounted Substation to offload 131H-422.
- Complete 4 kV voltage conversions and retire the 6S-Terrace Street Substation.

2023

- 78W-Martins Brook substation relocation and transformer replacement (C0010956). Substation construction.
- 2021 Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 7 of 8).
- Receipt of new large spare auto-transformer (C0031050).
- Receipt of replacement spare for unit utilized at 58C-SW Margaree Substation (C0031052).
- 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).
- Construct new 25/33/42 MVA 138 kV–25 kV Suzie Lake Substation complete with four 25 kV distribution feeders.
- Complete land transfer to enable the retention of 129H-Kearney Lake Substation.
- Re-align transmission structures on approach to the 129H-Kearney Lake Substation.
- Construct new 25/33/42 MVA 138 kV–25 kV Vista Drive Substation complete with three 25 kV distribution feeders in Stellarton.
- Purchase new 138 kV–25 kV, 15/20/25 MVA transformer and site at the intersection of 138 kV line L-6051 and Highway 1 (near Brushy Hill) for new Lacey Lake substation. Install Portable substation near site until substation is complete in 2024.
- Add a second 138 kV-25 kV, 25/33/42 MVA transformer and secondary buswork at 4C-Lochaber Road in Antigonish.
    - Replace existing 3/4/4.48 MVA Lower East Pubnico transformer with 7.5/10/12.5 MVA unit.

2024

- Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow.
- Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 8 of 8).
- Install 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 Barrington Passage transformer with 15/20/25 MVA unit and add additional feeder circuit.

2025

- Installation of a new 25/33/42 MVA, 138 kV-25 kV substation at Suzie Lake.

2026

- 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.
- Add a second 25/33/42 MVA, 138 kV-25 kV transformer at new Vista Drive substation in Stellarton.
- Replace 83V-Wolfville Ridge transformer 83V-T51 with a 138/69kV-25 kV, 15/20/25 MVA transformer.
- Replace 93V-Saulnierville transformer 93V-T51 with a 138/69 kV-25 kV, 15/20/25 MVA transformer.

2027

- Installation of a new 138/69 kV-25 kV, 15/20/25 MVA substation in Lower Truro tapped to Line L-5028.

2028 - 2031

- There are currently no planning studies with transmission recommendations beyond 2028, but NS Power anticipates that more projects will be identified as coal-fired generation is phased out and electrification advances.

8.4 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
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 in Q3 2021 due to an influx of Feasibility Studies related to the Rate Base Procurement process for the procurement of 1100 GWh (~350MW) of renewable generation within the province. Work on the Western study is anticipated to resume in Q3 2022.

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 2020 IRP evaluated a robust set of future planning scenarios, with modeling assumptions that were created with comprehensive stakeholder input. IRP Scenario 3.1C forms the planning basis for the 2022 10-Year System Outlook as it more closely reflects the current load forecast (Section 2.0) and environmental and emissions policy (Section 5.0).

The evergreen IRP update (Section 3.2.2) scheduled for completion in 2022 is NS Power's commitment to continuously refining the IRP Action Plan and Roadmap items to reflect changes in the planning environment. This updated analysis will be used to inform future 10-Year System Outlook Reports and related long-term planning processes.