Nova Scotia Utility and Review Board

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

2021 10-Year System Outlook

NS Power

June 30, 2021

NON-CONFIDENTIAL

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1.0 INTRODUCTION

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 2021.

The 2021 10-Year System Outlook Report contains the following information:

- A summary of the Nova Scotia Power Incorporated (NS Power, Company) load forecast and 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 Sections 3-5. 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.
- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in Section 6. This Section also includes projections of the level of renewable energy available and discusses anticipated policy changes.
- A Resource Adequacy Assessment in Section 7.
- A discussion of transmission planning considerations in Section 8.
- Identification of transmission-related capital projects currently in the Transmission Development Plan in Section 9.
- A discussion of NS Power's ongoing COVID-19 pandemic response in Section 10.

[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)."

As discussed in Section 7.4, the Company's 2020 Integrated Resource Plan (2020 IRP) evaluated a robust set of future planning scenarios, with modeling assumptions that were created incorporating significant stakeholder input. The 2020 IRP documented capacity expansion/retirement modeling optimization results and associated insights over a 25-year planning horizon (2021-2045). The reference plan from the 2020 IRP (Scenario 2.0C) forms the planning basis for the 2021 10-Year System Outlook. For energy forecasting purposes, updated PLEXOS modeling for the inital three years 2022-2024 was completed and the reference plan from the 2020 IRP (Scenario 2.0C) provides the data for the period 2025-2031. Recently announced federal and provincial policy statements discussed in Section 6.3 have the potential to impact the future of the Company's thermal generation fleet if such statements become legislative and/or regulatory requirements. NS Power continues to monitor and evaluate such developments and to the extent they become law, NS Power will incorporate them into its planning studies and reflect them in future 10 Year-System Outlook Reports.

As discussed in Section 10, NS Power continues to monitor the ongoing COVID-19 pandemic and remains focused on the health and safety of employees, consultants, contractors, and their families. A response team is monitoring the situation, coordinating with authorities, and keeping employees informed via regular business updates. The economic effects of the COVID-19 pandemic and their impact on short and medium-term system planning continue to be evaluated.

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 2021 Load Forecast Report on April 30, 2021 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. NSR is expected to grow slowly until 2024, driven by increased residential customer count, electric heating in the residential sector, and industrial growth. Over the long term, this expected growth will be offset by anticipated 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, resulting in a reduction in overall load between 2025 and 2031. The net result of these inputs is an annual average decline of 0.1 percent in NSR compared to a peak demand forecast that remains flat.

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

Year	NSR (GWh)	Growth (%)
2011	11,907	-2.1
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*	11,039	3.0
2022*	11,005	-0.3
2023*	11,043	0.3
2024*	11,119	0.7
2025*	11,083	-0.3
2026*	11,047	-0.3
2027*	10,997	-0.5
2028*	10,974	-0.2
2029*	10,913	-0.5
2030*	10,876	-0.3
2031*	10,875	0.0

*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 Reduction (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. After accounting for the effects of DSM savings, system peak is expected to remain essentially flat on average 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 (%)
2011	265	-	1,903	2,168	2.5
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*	155	-	2,073	2,228	8.6
2022*	158	-4	2,062	2,225	-0.1
2023*	162	-12	2,065	2,240	0.7
2024*	162	-24	2,060	2,247	0.3
2025*	169	-36	2,053	2,257	0.5
2026*	170	-39	2,049	2,258	0.0
2027*	169	-39	2,046	2,254	-0.2
2028*	169	-39	2,044	2,251	-0.1
2029*	169	-38	2,044	2,251	0.0
2030*	168	-38	2,047	2,253	0.1
2031*	168	-37	2,057	2,262	0.4

*Forecast value

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

3.0 GENERATION RESOURCES

3.1 Existing Generation Resources

NS Power's generation portfolio is composed of a mix of fuel and technology types that include coal, petroleum coke, light and heavy oil, natural gas, biomass, wind and hydro. 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 6.1, 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 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** in Section 7.4.

Figure 3: 2021 Firm Generating Capability for NS Power and IPPs

Plant/System	Fuel Type	Winter Net Capacity [2] (MW)
Avon	Hydro	6.4
Black River	Hydro	21.4
Lequille System	Hydro	23.0
Bear River System	Hydro	35.5
Tusket	Hydro	2.3
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[3]	Hydro	0.0
Fall River	Hydro	0.5
Total Hydro		**354.9**
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	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[4]	Light Fuel Oil	66
Total Combustion Turbine		**231**

[2] Wind and Hydro are Effective Load Carrying Capability (ELCC) values. Please refer to Section 7.3 for further information.
[3] Annapolis is assumed to be out of service. Please refer to Section 3.2.3.
[4] Please refer to Section 3.2.2.

Plant/System	Fuel Type	Winter Net Capacity [2] (MW)
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.8
Post-2001Renewables (firm)[5]	IPPs	66.4
NS Power wind (firm) [5]	Wind	14.5
Community Feed-in Tariff (firm)[5]	IPPs	33.2
Total IPPs & Renewables		**139.9**
Total Capacity		**2416.9**

Figure 4: Firm Generating Capability for Wholesale Market Participants

Wholesale Market Participant	Fuel Type	Winter Net Capacity [6] (MW)
Backup Top-Up (BUTU)[7]	Wind [Ellershouse[8]]	4.2
Backup Top-Up (BUTU)	Import Contract[9]	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*

[5] 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 7.3.1.
[6] Assuming 18 percent ELCC for wind and 0 percent for non-firm Imports to align with current NS Power planning practices. This matter is pending before the UARB.
[7] Wholesale Market Backup/Top-up Service (BUTU) Tariff participants currently include the Municipal load for Berwick, Mahone Bay, Antigonish and Riverport.
[8] Ellershouse wind farm owned by Alternative Resource Energy Authority (AREA).
[9] Import contract is currently delivered via the Nova Scotia/New Brunswick Intertie.

Power Capability and Synchronous Condenser Reactive Power Capability[10] which was approved by Federal Energy Regulatory Commission (FERC) on March 20, 2014.

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 preparing a capital application for 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 the redeveloping the Mersey system:[11]

> The Mersey Hydro system was analyzed during the Resource Screening phase of the IRP (described in Section 4.2.2) 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),

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

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

IRP participants expressed a desire to examine the Mersey system specifically via a PLEXOS sensitivity.

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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 was 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 refurbishment.

3.1.3 Wreck Cove Hydro

Wreck Cove Hydro 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. In 2020, NS Power submitted a capital application to the NSUARB to perform Life Extension & Modernization (LEM) work for the Wreck Cove Generating Station.[12] The Nova Scotia Utility and Review Board (NSUARB, Board) approved the proposed generator, turbine and spherical valve portion of work.[13] Specifically, as part of the 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.

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

[13] M09596, NS Power Wreck Cove Life Extension and Modernization, NSUARB Order, February 2, 2021.

3.2 Changes in Capacity

Figure 5 provides the firm Supply and DSM capacity changes in accordance with the assumption set developed for the 2020 IRP and the 2021 Load Forecast.

Figure 5: Firm Capacity Changes & DSM

New Resources 2022-2031	Net MW
DSM Peak reduction	290
Demand Response (Firm contribution)[14] programs	37
Total Demand Side MW Change Projected Over Planning Period	**327**
Biomass	43
Assumed Unit Retirements/Lay-ups[15]	-148
Maritime Link Import - Base Block	153
Tidal (Firm capacity)	6
IRP Reference Plan Additions:	
Firm imports over existing infrastructure	165
Battery	10
Natural Gas Units	259
New Wind Build (Firm capacity)	40
IRP Reference Plan Retirements:	
Trenton 5	-150
Tufts Cove 1 & 2	-171
Pt Aconi	-168
Total Firm Supply MW Change Projected Over Planning Period	**40**

[14] Represents the firm contribution of demand response programs in 2031 assuming an ELCC of 48 percent. Refer to Section 2.0, Figure 2 for the annual DR totals from 2022 to 2031.

[15] Retirement of Lingan 2 after the Martime Link Base Block provides firm capacity service.

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. However, the specific type, quantity and timing of future resource additions and retirements remains uncertain as several key actions arising from the 2020 IRP continue and further clarity and legislative direction is obtained in response to recent government policy announcements.

Figure 6: Additions and Retirements as per the 2020 IRP Reference Plan (2.0C)

2020 IRP Reference Plan (2.0C)[17]		
	Additions	**Retirements**
2022	Firm import opportunities on existing transmission infrastructure (165 MW)	
2023	Reciprocating Engine (9.3 MW)	Trenton 5 (- 150 MW)
	Battery[18] (10 MW)	
2024		
2025		
2026	Combustion turbines (150 MW)	Tufts Cove 1 & 2 (- 171 MW)
2027		
2028		
2029		
2030	New Wind additions (Installed capacity 400 MW - Firm 40 MW based on marginal ELCC of 10%)[19]	Pt Aconi (- 168 MW)
	Combustion turbine (100 MW)	
2031		

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

[17] Lingan 2 is assumed to be retired prior to 2022 in IRP Scenario 2.0C.

[18] Delayed from 2021 to 2023 due to lead times.

[19] See Section 7.3 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.

3.2.2 Victoria Junction Combustion Turbine

On March 23, 2020 the NSUARB issued its decision[20] to decline approval of the Company's capital application for the work related to the refurbishment of the Victoria Junction Unit 2 Combustion Turbine (VJ2). VJ2 is a 33 MW combustion turbine that provides black start capability, 10-minute reserve, Volt-Ampere Reactive support and additional firm capacity to the NS Power electrical system. In its decision, the NSUARB stated:

> NS Power may re-apply following the completion of the review of existing CT (oil) resources during the 2020 IRP proceeding or after a comprehensive alternate analysis of all the Company's oil CTs has been completed.

The 2020 IRP included analysis which confirmed that existing combustion turbine resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled levels of sustaining capital investment.

On May 25, 2021, NS Power resubmitted a capital application to the NSUARB[21] for the refurbishment of VJ2. For the purposes of this study, the Company has forecast the inclusion of the firm capacity provided by VJ2 in NS Power's resource mix.

[20] M09560, NSUARB letter to NS Power re Approval of 2020 Capital Work Order (P-520), March 23, 2020.

[21] M10129, NS Power Application for Approval of VJ2 Engine Refurbishment (P-128.20), May 25, 2021.

3.2.3 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 filed an application with the NSUARB[22] for approval of the accounting treatment of the unrecovered net book value of the assets. The application is currently before the NSUARB. For the purposes of the 10-Year System Outlook, NS Power has assumed no capacity contribution from the Annapolis Tidal Generating Station.

3.3 Unit Utilization Forecast

The Company typically forecasts 10 years of utilization and investment projections in this Report. There are many operational realities, such as the prices of fuel and power or changes in policy or regulation that could trigger a significant shift in the utilization forecast to provide the most economic system dispatch for customers.

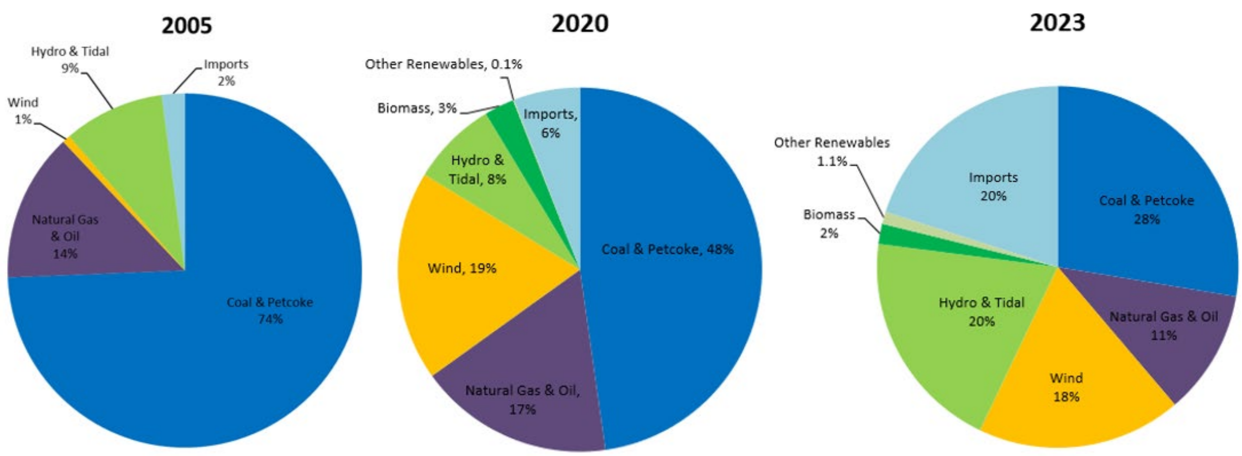
3.3.1 Evolution of the Energy Mix in Nova Scotia

NS Power's energy production mix has undergone significant changes over the last 15 years. Since the implementation of the *Renewable Electricity Standards* (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 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 and 3.2, while the energy output of conventional

[22] 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.

units is being displaced by renewable resources. **Figure 7**[23] below illustrates this change with the actual energy mix from 2005 and 2020 and the updated forecast for 2023.

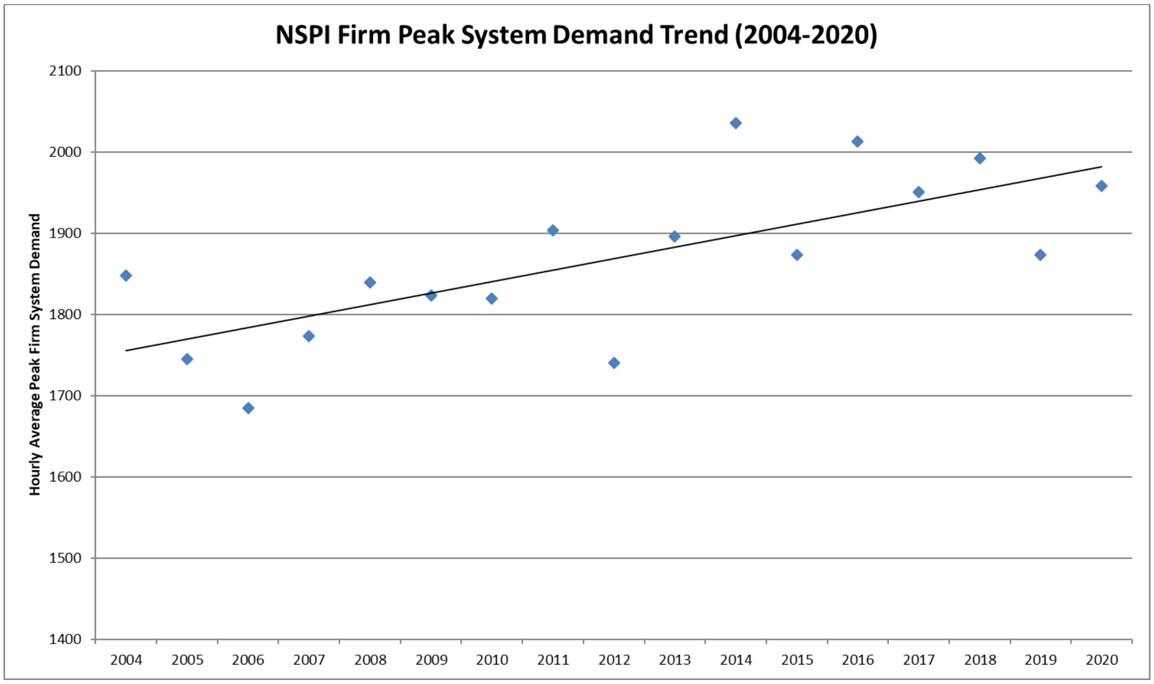
Figure 7: 2005, 2020 Actual and 2023 Forecast Energy Mix



As illustrated in **Figure 8**, NS Power's historical firm peak demand has been increasing at an average rate of approximately 1 percent per year. After accounting for the effects of DSM savings, the system peak is expected to remain essentially flat on average over the forecast period. Future growth is expected to be mitigated through DSM, Demand Response strategies and underlying efficiency improvements. While energy is increasingly being produced by new renewable sources, the capacity required to serve system demand will largely continue to be served by dispatchable conventional resources together with firm imports. These resources also provide other critical services to the system such as load following.

23 Consistent with the provisions of the *Renewable Electricity Regulations*, in 2021 the category of Imports includes ML Surplus energy while the category of Hydro includes ML NS Base Block and Supplemental Energy from the Muskrat Falls hydro project.

Figure 8: Peak System Demand Trend



3.3.2 Projections of Unit Utilization

The 2020 IRP provided an in-depth analysis of unit utilization. The reference plan from the 2020 IRP (Scenario 2.0C) forms the planning basis for the 2021 10-Year System Outlook. For energy forecasting purposes, updated PLEXOS modeling for the inital three years 2022-2024 was completed and the reference plan from the 2020 IRP (Scenario 2.0C) provides the data for the period 2025-2031. As anticipated new legislation and regulations come into effect, the effect of these changes on unit utilization will be reflected, as appropriate, in future planning analyses. The three-year 2022-2024 update allowed updated assumptions regarding fuel and market prices, load forecast, system constraints and generating parameters to be reflected in this report.

Figure 9 below provides the current forecast unit utilization of NS Power's steam fleet.

Figure 9: NS Power Steam Fleet Unit Utilization Forecast

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Lingan 1	Capacity Factor (%)	42	59	48	25	25	27	25	33	20	20
	Unit Cycles (Ranges)	< 10	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	10 - 25
	Service Hours	5555	8271	6468	3369	3359	3760	3359	4777	2564	2546
Lingan 2	Capacity Factor (%)	3	0	0	0	0	0	0	0	0	0
	Unit Cycles (Ranges)	< 10	0	0	0	0	0	0	0	0	0
	Service Hours	305	0	0	0	0	0	0	0	0	0
Lingan 3	Capacity Factor (%)	30	24	27	42	27	27	28	23	24	22
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	25 - 50	50 - 100	25 - 50	50 - 100	25 - 50	25 - 50	25 - 50
	Service Hours	3665	2680	3493	6195	3820	3898	4131	3113	2979	2661
Lingan 4	Capacity Factor (%)	43	38	40	27	27	24	25	24	19	22
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50	25 - 50	10 - 25
	Service Hours	5796	4680	5049	3474	3356	3119	3279	3323	2452	2702
Point Aconi	Capacity Factor (%)	23	26	25	30	64	66	64	59	0	0
	Unit Cycles (Ranges)	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10	0	0
	Service Hours	2860	2955	2891	3076	6821	7196	6868	6345	0	0
Point Tupper	Capacity Factor (%)	34	31	37	67	62	61	61	62	50	51
	Unit Cycles (Ranges)	10 - 25	< 10	10 - 25	< 10	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50
	Service Hours	4464	3770	4647	7524	7033	7215	7060	7317	5510	5706
Trenton 5	Capacity Factor (%)	1	0	0	0	0	0	0	0	0	0
	Unit Cycles (Ranges)	< 10	0	0	0	0	0	0	0	0	0
	Service Hours	100	0	0	0	0	0	0	0	0	0
Trenton 6	Capacity Factor (%)	43	45	46	60	60	58	58	57	37	35
	Unit Cycles (Ranges)	< 10	< 10	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	5739	6078	5862	6781	6788	6625	6705	6458	3720	3633
Tufts Cove 1	Capacity Factor (%)	19	15	13	7	0	0	0	0	0	0
	Unit Cycles (Ranges)	10 - 25	< 10	< 10	10 - 25	0	0	0	0	0	0
	Service Hours	2526	1870	1613	892	0	0	0	0	0	0
Tufts Cove 2	Capacity Factor (%)	10	9	11	9	0	0	0	0	0	0
	Unit Cycles (Ranges)	25 - 50	25 - 50	25 - 50	10 - 25	0	0	0	0	0	0
	Service Hours	1781	1413	1781	1599	0	0	0	0	0	0
Tufts Cove 3	Capacity Factor (%)	19	21	28	22	26	22	22	21	19	16
	Unit Cycles (Ranges)	25 - 50	25 - 50	25 - 50	10 - 25	50 - 100	25 - 50	25 - 50	25 - 50	25 - 50	25 - 50
	Service Hours	3415	3217	4435	4194	4643	3955	4009	3880	2804	2493
Tufts Cove 4	Capacity Factor (%)	69	73	67	66	68	68	66	69	67	68
	Unit Cycles (Ranges)	50 - 100	50 - 100	50 - 100	> 100	> 100	> 100	> 100	> 100	> 100	> 100
	Service Hours	6872	7220	6657	6377	6464	6518	6403	6819	6356	6429
Tufts Cove 5	Capacity Factor (%)	66	72	73	69	64	65	65	65	67	67
	Unit Cycles (Ranges)	50 - 100	50 - 100	50 - 100	> 100	> 100	> 100	> 100	> 100	> 100	> 100
	Service Hours	6622	7126	7316	6730	6114	6205	6281	6412	6357	6317
Tufts Cove 6	Capacity Factor (%)	39	42	38	41	44	44	44	43	45	45
	Unit Cycles (Ranges)	25 - 50	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50	10 - 25	25 - 50	50 - 100	50 - 100
	Service Hours	7623	7753	6928	7595	7359	7209	7496	7265	7140	7048

3.3.3 Steam Fleet Retirement Outlook

As part of the 2020 IRP, NS Power developed updated retirement scenarios and updated its forecast of major investment intervals for those units. The recent federal and provincial policy announcements to lower GHG emissions discussed in Section 6.3 may affect steam unit retirement schedules. Legislative changes reflecting these policy anouncements, when passed, will be reflected in future studies.

Figure 6 in Section 3.2.1 above provides the retirement schedule from Scenario 2.0C, the Reference Plan from the 2020 IRP. Lingan Unit 2 is planned for retirement following the commencement of the delivery of the Nova Scotia Block of energy and related firm capacity from the Muskrat Falls and is assumed to be retired in Scenario 2.0C.

Unit utilization and reliability objectives have long been the drivers for generator 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 the latest understanding of 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 the 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. Refer to **Figure 10** below.

Figure 10: Utilization Factor

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

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

- Service hours have become a more important factor to consider with increased penetration of variable-intermittent generation, as units are frequently running below their full capacity while providing load following and other essential reliability services for wind integration. For example, if a unit operates at 50 percent of its capacity for every hour of the year, then the capacity factor would be 50 percent. In a traditional model, this would suggest a reduced level of investment required, commensurate with decreased capacity factor. However, many failure mechanisms are a function of operating hours (e.g. turbines, some boiler failure mechanisms, and high energy piping) and the number of service hours (which in this example is every hour of the year) is not reflected by the unit's capacity factor. Additionally, some failure mechanisms can actually 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 11 below provides the projected sustaining investments based on the anticipated utilization forecast in Section 3.3.2. Estimates of unit sustaining investment are forecast by applying the UF, related life consumption and known failure mechanisms. NS Power does not include unplanned failures in sustaining capital estimates. These estimates are evaluated at the asset class level; some asset class projections are prorated by the UF and others have additional overriding factors. For example, the use of many instrument and electrical systems is a function of calendar years, as they operate whether a unit is running or not. Investments for coal and ash systems are a direct function of capacity factor, as they typically have material volume-based failure mechanisms. In contrast, the UF is directly applicable to the investment associated with turbines, boilers and high energy piping. Major assets are regularly 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 11: Forecast Unit Utilization Factors

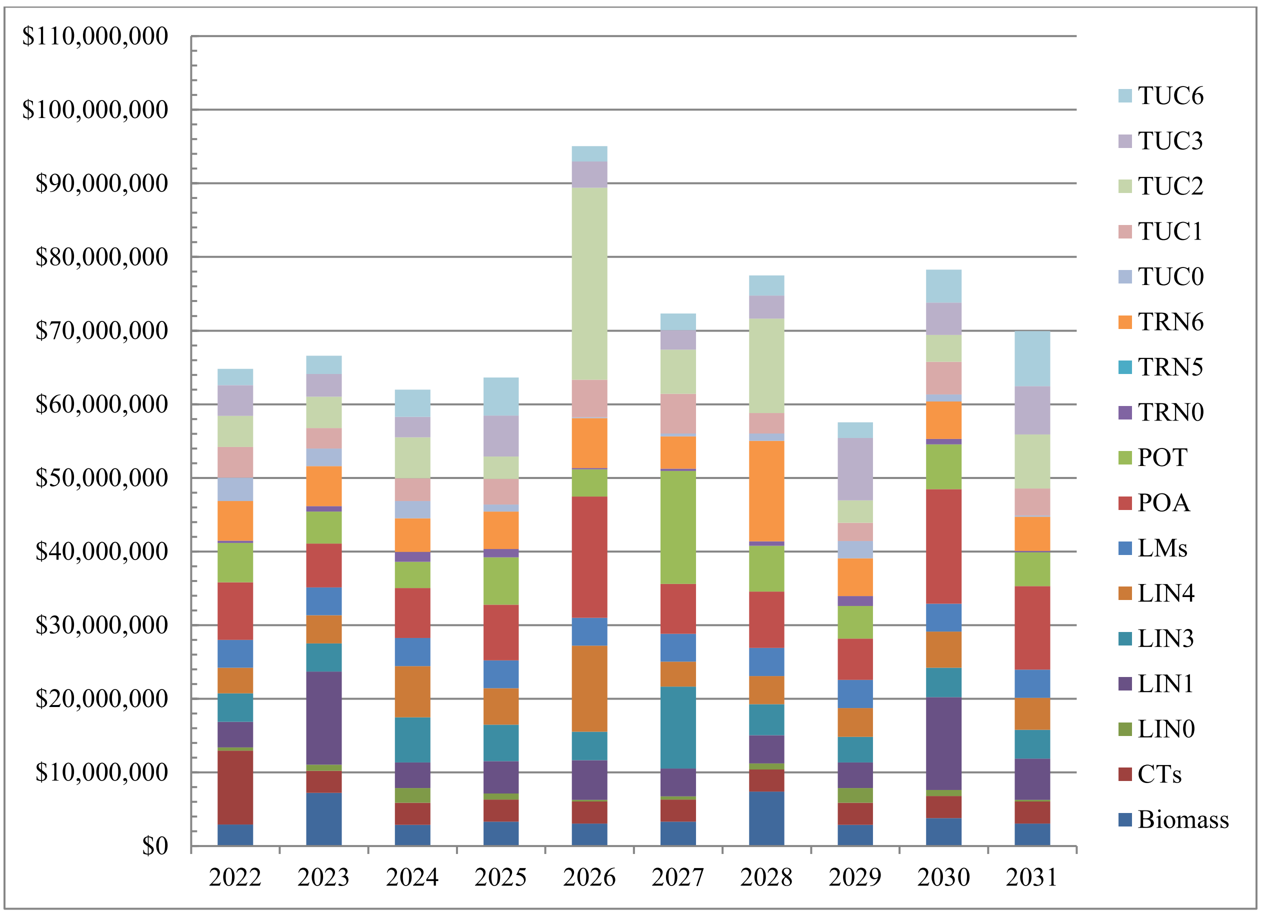
Unit	UF(2022-2026)	UF(2027-2031)
LIN-1	Medium	Medium
LIN-2	Off	Off
LIN-3	Medium	Medium
LIN-4	Medium	Medium
PHB-1	High	High
POA-1	Medium	High
POT-2	Medium	High
TRE-5	Low/Off	Off
TRE-6	High	High
TUC-1	Low	Off
TUC-2	Medium	Off
TUC-3	Medium	Medium
TUC-4	High	High
TUC-5	High	High
TUC-6	High	High

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 12** 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.

Figure 12: Forecast Annual Investment (in 2021$) by Unit



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

4.0 NEW SUPPLY SIDE FACILITIES

As of June 18, 2021 NS Power has 21 active Transmission Connected Interconnection Requests (1408.8 MW) and 15 active Distribution Connected Interconnection Requests (92.45 MW) at various stages of interconnection study. The Advanced Stage Interconnection Request Queue is described in Section 5.

Proponents of transmission projects request Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). NRIS refers to a firm transmission interconnection request with the potential requirement for transmission reinforcement upon completion of the System Impact Study (SIS). ERIS refers to an interconnection request for firm service only to the point where transmission reinforcement would be required. Results of the transmission interconnection studies assessing the transmission reinforcement required to support transmission projects will be incorporated into future transmission plans.

Distribution projects do not receive a NRIS or ERIS designation.

5.0 QUEUED SYSTEM IMPACT STUDIES

Figure 13 below provides the current combined Transmission and Distribution Advanced State Interconnection Queue.

Figure 13: Combined Transmission & Distribution Advanced Stage Interconnection Queue as of June 18, 2021

Queue Order	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Inter-connection Point	Type	In-Service date DD-MMM-YY[24]	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	01-Nov-21	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	568	21-May-19	Cumberland	2.0	2.0	22N-404	Solar	01-Sep-21	GIA Executed	N/A
8-D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	29-Jan-21	GIA Executed	N/A
9-T	574	27-Aug-20	Hants	58.8	58.8	L-6051	Wind	30-Jun-23	FAC in Progress	NRIS
10-D	595	11-Mar-21	Halifax	0.1	0.1	1H-454	Battery	11-Jan-21	SIS in Progress	N/A
11-T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	01-Dec-22	SIS Milestones Met	NRIS

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

[24] 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.

Procedures (GIP) or Distribution Generator Interconnection Procedures (DGIP). **Figure 13** above 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 5.1.

5.1 OATT Transmission Service Queue

As of June 15, 2021 as shown in **Figure 14**, there are four ongoing requests in the OATT Transmission Queue.

Figure 14: 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	800	SIS in Progress
3	TSR 412	January 19, 2021	Point-to-point	Woodbine - NS	January 1, 2025	500	SIS in Progress
4	TSR 413	April 14, 2021	Network	Antigonish - NS	January 1, 2022	8.792	Application Accepted

*Indicates project as being located near provincial border.

In its Decision on the 2020 10-Year System Outlook, the UARB provided the following direction with respect to the information provided about Requests in the OATT Transmission Queue:[25]

> 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 14** under Project Location reflects the non-confidential information provided in the customer's application. Details regarding the location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted are deemed confidential under Section 17.2 of the OATT[26] 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 14**.

System upgrades related to Transmission Service Request 400 now have their design complete. Execution of upgrades is pending the procurement of materials and is planned for Q4 2021.

Studies are being performed to determine the system upgrades necessary for TSR 411 and TSR 412.

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

[26] Nova Soctia 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

6.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

6.1 Renewable Electricity Requirements

The Nova Scotia *Renewable Electricity Standards* (RES) include a renewable energy requirement for NS Power of 25 percent of energy sales in 2015, and 40 percent in 2020.[27] As discussed below in Section 6.3, in February 2021, the Government of Nova Scotia also announced its intention to implement a RES of 80 percent by 2030. As of the time of preparing this study, an updated 2030 RES requirement has not yet been reflected in regulations.

In addition, Nova Scotia has a Community Feed-in-Tariff (COMFIT) for projects which include community ownership that are connected to the distribution system and Net Metering legislation for renewable projects.[28] 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.[29]

[27] *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).

[28] Effective December 18, 2015, the *Electricity Act* reduced the maximum nameplate capacity for Net Metering from 1,000 kW to 100 kW. Net metering applications submitted on or after December 18, 2015 are subject to the new 100 kW limit. The legislation also closed the COMFIT to new applications.

[29] *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).

NS Power has complied with or exceeded the renewable electricity requirement in all applicable years. From 2015 to 2020 the Company served 26.6 percent (2015), 28 percent (2016), 29 percent (2017), 30 percent (2018), 30 percent (2019) and 29 percent of sales (2020) using qualifying renewable energy sources.

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.[30] 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. The Minister's Alternative Compliance Plan, in part, directs NS Power to make up the shortfall extending the compliance period for meeting the 40 percent renewable energy standard over the three calendar years 2020, 2021, and 2022. The Company is on track to meet its RES compliance requirements for the 2020 through 2022 period.

On May 6, 2021 Newfoundland and Labrador Hydro wrote to the Newfoundland and Labrador Board of Commissioners of Public Utilities, stating, "Based on the schedules presented above, the overall Muskrat Falls Project completion date is currently November 14, 2021."

The RES Compliance Forecast in **Figure 15** illustrates the full amount of RES-eligible energy forecast to be available to the Company if the Nova Scotia Block energy flow begins on December 1, 2021.

[30] https://muskratfalls.nalcorenergy.com/march-27-2020-covid-19-update-from-nalcor-on-the-muskrat-falls-project/

Figure 15: RES Compliance Forecast

RES Compliance Forecast[31]			
	2022	**2023**	**2024**
Energy Requirements (GWh)			
NSR including DSM effects	11,005	11,043	11,119
Losses	684	687	692
Sales	10,321	10,356	10,427
RES (%) Requirement	40%	40%	40%
RES Requirement (GWh)	**4,128**	**4,142**	**4,171**
Renewable Energy Sources (GWh)			
NS Power Wind	264	264	264
Post-2001 IPPs	770	770	770
PH Biomass	290	290	290
COMFIT Wind Energy	523	523	523
COMFIT Non-Wind Energy	15	15	15
Eligible Pre-2001 IPPs	80	82	77
Eligible NSPI Legacy Hydro	894	885	896
REA procurement (South Canoe/Sable)	357	357	357
Compliant Renewable Import	1,134	1,134	1,134
Forecast Renewable Energy (GWh)	**4,328**	**4,320**	**4,327**
Forecast Surplus or Deficit (GWh)	**199**	**178**	**156**
Forecast RES Percentage of Sales	**42%**	**42%**	**41%**

*This assumes the full year of Maritime Link energy flow.

[31] NSR and Losses are provided in the 2021 NS Power Load Forecast Report, Table A-1, April 30, 2021 (M10109).

6.2 Environmental Regulatory Requirements

The Nova Scotia *Greenhouse Gas Emissions Regulations*[32] specify emission caps for 2010-2030, as outlined in **Figure 16**. The net result is a hard cap reduction from 10.0 to 4.5 million tonnes over that 20-year period, which represents a 55 percent reduction in CO_2 release over 20 years. Carbon emissions in Nova Scotia from the production of electricity in 2030 are forecast to have decreased by 58 percent from 2005 levels.

Figure 16: Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes
2014-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

The *Sustainable Development Goals Act*[33] states 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

[32] *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.

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

a "net zero" by 2050 by balancing greenhouse gas emissions with greenhouse gas removals and other offsetting measures.

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 which may be offered for auction by the province. Nova Scotia Power is forecasting that the GHG credits available for the company to purchase will be approximately 0.05 Mt annually. Although bilateral GHG trades among participants are permitted, there have been no bilateral trades reported to date and any liquidity in this market is likely to be slow to develop. Due to limited GHG credit purchase opportunities, the primary means of meeting the caps is a reduction in thermal generation from the existing coal-fired generating units, replaced by low-emitting energy.

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 17**, 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 17: 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 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 will be subject to fuel surcharges under the *Cap and Trade Regulations*.

The Nova Scotia *Air Quality Regulations*[34] specify emission caps for sulphur dioxide (SO_2), nitrogen oxides (NO_X), and mercury (Hg). These regulations were amended to extend from 2020 to 2030, effective January 1, 2015. The amended regulations replaced annual limits with multi-year caps for the emissions targets for SO_2 and NO_X.

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 18**.

[34] *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.

Figure 18: Emissions (SO2, NOx, Hg)

<table>
<tr><th>Multi-Year Caps Period</th><th>SO_2 (t)</th><th>SO_2 (t) Annual Max</th><th>NO_X (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. NO_X 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. NO_X reductions are being addressed through reductions in thermal generation and the previous installation of Low NO_X Combustion Firing Systems. Mercury reductions are being accomplished through reduced thermal generation, changed fuel blends and the use of Powder Activated Carbon systems. NS Power offered a mercury recovery program, such as recycling light bulbs or other mercury-containing consumer products, which reduced the amount of mercury going into the environment through landfills. The amount of mercury diverted in 2019 resulted in the total amount of credits exceeding the credit target for the program; therefore, NS Power no longer funded the program as of January 31, 2020. 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.

6.3 Anticipated Policy Changes

Until the federal coal phase-out policy changes announced in the fall of 2016,[35] NS Power's operation of and planning for its coal-fired generation units proceeded consistent with the provisions of the Agreement on Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (the Equivalency Agreement). The Equivalency Agreement was finalized in May 2014 and commenced in July 2015, contemporaneous with the effective date for the current federal *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*.

In November 2016, the Province of Nova Scotia announced that an agreement-in-principle had been reached with the Government of Canada to develop a new equivalency agreement driven by amendments proposed by the Federal Government to the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*.[36] On March 30, 2019 the Renewal of this Equivalency Agreement was published in Canada Gazette I. This Equivalency is valid until 2024, with notional direction to 2029.

The Federal Government recently announced its intention to cease all coal-fired electricity generation by 2030. The Government of Nova Scotia has indicated a similar intention with respect to the Province of Nova Scotia. In February 2021 the Government of Nova Scotia announced its intention to implement a Renewable Energy Standard of 80 percent by 2030. In addition, the Federal Government has also indicated its intention to increase the cost of GHG emissions by increasing the Federal carbon price by $15/tonne beginning in 2023 and reaching a level of $170/tonne by 2030.

[35] https://www.canada.ca/en/environment-climate-change/news/2017/11/taking_action_tophase-outcoalpower.html

[36] Vol. 152, No. 7 Canada Gazette Part I Ottawa, Saturday, February 17, 2018.

In response to these recent governmental policy statements and to better prepare for the potential that these policy statements become law, NS Power is developing a comprehensive plan to transform its generation fleet, eliminating coal-fired generation by 2030 and reducing GHG emissions to 1-2 Mt/year by 2030. 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 and that 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.

7.0 RESOURCE ADEQUACY

7.1 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.[37]

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*[38] 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.

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

[38] 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, or 220 MW, capped at the largest on-line unit in Nova Scotia. When Point Aconi is online, NS Power maintains a ten-minute operating reserve of 168 MW (equivalent to Point Aconi net output), of which approximately 33 MW 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.

7.2 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*[39] 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.

[39] 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. In advance of the 2020 IRP, NS Power engaged Energy+Environmental Economics Consulting, LLC (E3) to undertake a PRM and capacity value study. The study found that in order to meet a 0.1 days/year loss of load expectation (LOLE) target and comply with the NPCC reliability requirements, NS Power should maintain a PRM between 17.8 percent and 21 percent.[40] The range in target PRM is due to a higher and lower estimate of operating reserve requirements for the NS Power system. NS Power studied the appropriate calculation of its PRM as part of the 2020 IRP.[41] The 2020 IRP confirmed that this PRM target was appropriate for long term planning, as noted in the report:

> There are two alternative PRM accounting methods commonly used in the industry, based on using a unit's unforced capacity (UCAP) or installed capacity (ICAP) values. While either method will result in the same reliability standard and the same total quantity of effective capacity, the methods differ in how they measure qualifying capacity. ICAP accounting credits traditional dispatchable resources (e.g., coal, natural gas) at their nameplate capacity, without considering forced outage de-rates, and credits energy-limited resources, including solar, wind, hydro, and battery storage, at their effective load carrying capacity (discussed in further detail below). As an alternative, utilities and capacity markets are beginning to transition to an unforced capacity (UCAP) rather than installed capacity (ICAP) approach to determine the PRM for purposes specifically associated with capacity expansion modeling. This UCAP value adjusts the peak contribution of thermal resources to account for their forced outage or deratings, instead accounting for these resources based on their UCAP or unforced capacity value. This approach puts existing and candidate thermal and renewable resources on an "equal footing" by accounting for the resources' contributions to peak in a consistent way. For the 2020 IRP, Nova Scotia Power used its existing 20 percent ICAP PRM, which the E3 planning and reserve margin study verified was within the range of PRMs consistent with the reliability criterion, and converted this to an equivalent 9 percent UCAP PRM. This UCAP translated value was adopted for the capacity expansion modeling only, based on feedback and discussion with IRP

[40] M08929, Energy + Environmental Economics, Planning Reserve Margin and Capacity Value Study for Nova Scotia Power Inc. July 2019 found as Attachment 17 to NS Power's Pre-IRP Deliverables Report located at https://irp.nspower.ca/documents/pre-irp-deliverables/.

[41] M08929, Nova Scotia Power, IRP Final Report, November 27, 2020, page 40.

> participants, to ensure that renewable resources (primarily wind) would face an equivalent crediting formula to new and existing thermal alternatives. This choice does not change the reliability criterion or use of ICAP PRM calculations in other reporting and analysis. The PRM target will remain appropriate for as long as the given load characteristics and reserve requirements remain consistent. As Nova Scotia Power begins to serve new electrification load, or as significant changes start to occur to the overall generation mix, the appropriate PRM may require re-evaluation and adjustment.

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 such as load following (ramping capability) and emissions compliance. The optimal capacity requirement is determined through a long-term planning exercise such as the 2020 IRP, as discussed in Section 7.4 below.

7.3 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.

By letter dated October 5, 2018[42] 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 E3[43] 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 be 11 to 9 percent. In the 2020 IRP, the Company used 10 percent for the ELCC value of new wind. The ELCC value of Hydro was determined to be 95 percent. 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 BUTU Tariff, 10 percent capacity value of new wind, and 95 percent for hydro.

Please refer to Section 7.3.1 regarding the inclusion of ERIS wind resources.

[42] M08059, UARB Decision Letter, Generation Utilization and Optimization, October 5, 2018.

[43] 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/

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.

7.3.1 Energy Resource Interconnection Service Connected Resources

In the 2018, 10-Year System Outlook Report, NS Power provided a study to determine the potential capacity contribution of ERIS facilities based on current system configuration and conditions. The study concluded that existing ERIS facilities can operate as though they are NRIS facilities and therefore can contribute to system capacity for the purposes of resource planning at this time without the requirement for additional system upgrades. The transmission system upgrades undertaken to enable the transmission of Maritime Link energy across Nova Scotia contributed to the change to ERIS facility capacity treatment.

Consistent with this, and for the purposes of reflecting this potential additional capacity in this Report, NS Power has applied a capacity value of 18 percent to existing wind resources, both ERIS and NRIS, in this Report. Please refer to Section 7.3 for further information on the capacity study used to determine the 18 percent.

This represents a new area for resource planning and remains subject to change. Until these matters are better understood it remains premature to make longer-term resource planning decisions based on this capacity addition. The Company will continue to monitor this resource planning input and will refine the capacity estimates as required. Changes, if necessary, will be incorporated within future 10-Year System Outlook Reports.

7.4 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 capacity deficit from 2022 until 2024. Solutions for capacity shortfalls will be evaluated including access to firm capacity if required. 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 7.2, the PRM provides a basis for the minimum required firm generation NS Power must maintain to comply with NPCC reliability criteria; it does not necessarily represent the optimal or maximum required capacity to serve other system requirements such as wind-following (ramping capability) and emissions compliance. In its Final Report submitted to the NSUARB in the Generation Utilization and Optimization proceeding,[44] Synapse stated:

> 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

[44] 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.

> (long-term planning and short-term dispatch) is intended to allow capture of all these moving parts when optimizing retirement and build decisions.[45]

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 appropriateness of any unit retirements, have been evaluated in the 2020 IRP and will be analyzed further as NS Power updates its long term planning analyses.

The reference plan from the 2020 IRP (Scenario 2.0C) forms the planning basis for the 2021 10-Year System Outlook.

[45] *Ibid* at Section 3.1.

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

	Load and Resources Outlook for NSPI - Winter 2021/2022 to 2030/2031 (All values in MW except as noted)										
		2021/ 2022	**2022/ 2023**	**2023/ 2024**	**2024/ 2025**	**2025/ 2026**	**2026/ 2027**	**2027/ 2028**	**2028/ 2029**	**2029/ 2030**	**2030/ 2031**
A	Firm Peak including effects of DSM & DR[46]	2,062	2,065	2,060	2,053	2,049	2,046	2,044	2,044	2,047	2,057
B	Required Reserve (Ax20%)	412	413	412	411	410	409	409	409	409	411
C	Required Capacity (A+B)	2,475	2,478	2,472	2,463	2,459	2,455	2,453	2,453	2,457	2,468
D	Existing Resources (NS Power and IPPs) [47]	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417
E	Existing Resources (Wholesale Market Resources)[48]	4	4	4	4	4	4	4	4	4	4
F	Total Existing Resources	2,421	2,421	2,421	2,421	2,421	2,421	2,421	2,421	2,421	2,421
	Firm Resource Additions:										
G	Thermal Additions[49]	43									
H	Thermal Retirements[50]	-148									
I											
J	Tidal[51]	2	1	1	1			2			
K	Hydro[52]		-108		101						
L	Maritime Link Import	153									
M	IRP Additions[53]	165	19			150				140	
N	IRP Retirements[53]		-150			-171				-168	
O	Total Annual Firm Additions (G+H+I+J+K+L+M+N)	215	-237	1	102	-21	0	2	0	-28	0
P	Total Cumulative Firm Additions (O+P of the previous year)	215	-23	-21	80	59	59	61	61	33	33
Q	Total Firm Capacity (F+P)	2,636	2,399	2,400	2,501	2,480	2,480	2,482	2,482	2,454	2,454
	+ Surplus/- Deficit (Q - C)	161	-80	-73	38	22	25	29	29	-3	-14
	Reserve Margin % [(Q - A)/A]	28%	16%	16%	22%	21%	21%	21%	21%	20%	19%

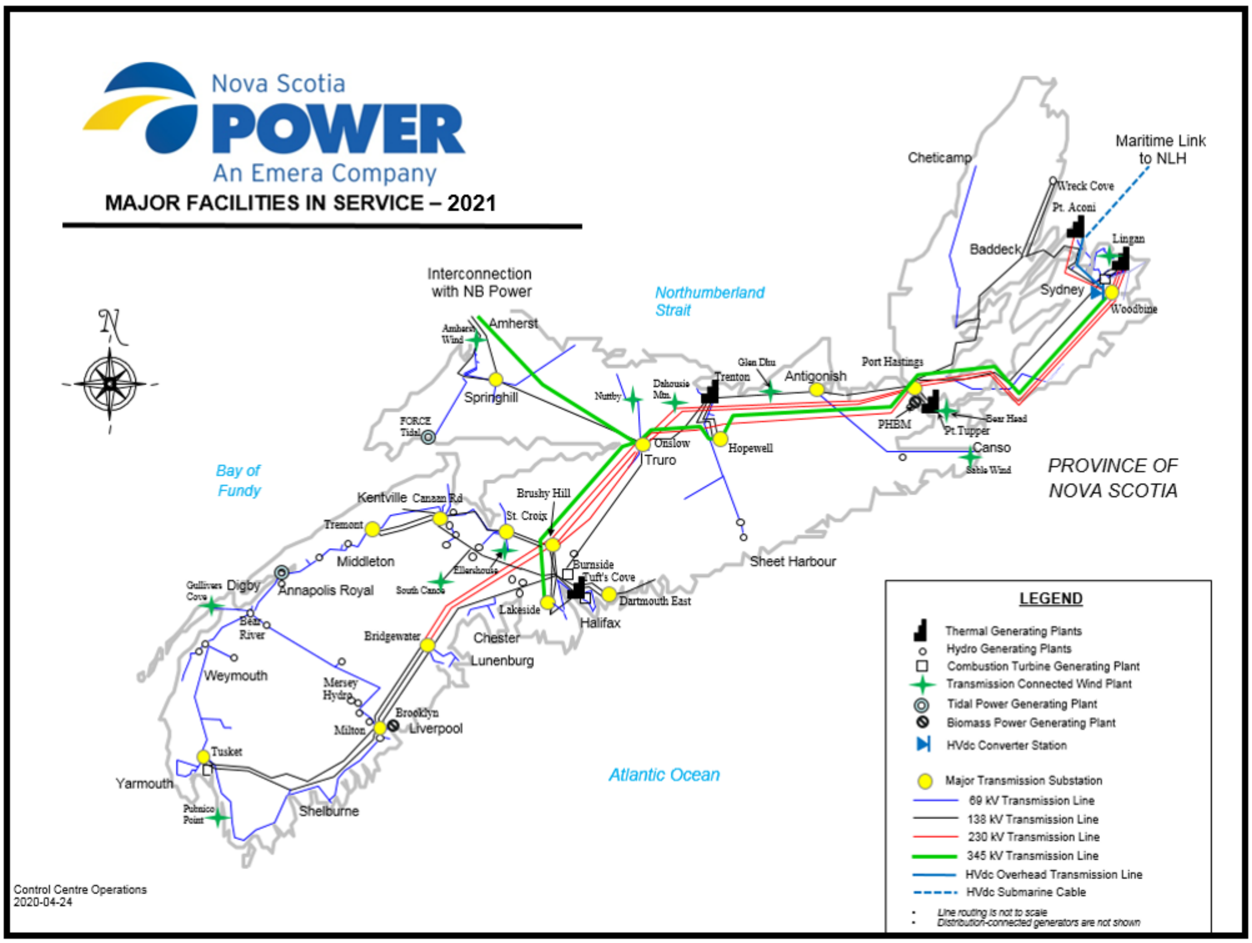
[46] Firm peaks as per 2021 Load Forecast including the effects of both DSM and DR programs as shown in Section 2.0, Figure 2.
[47] Existing Resources NS Power-owned and IPPs as shown in Section 3.1, Figure 3
[48] Existing Resources Wholesale Market Resources - resources managed by participants in the wholesale market as shown in Section 3.1, Figure 4.
[49] PH Biomass assumed to transfer to NRIS service in Q4 2021.
[50] Lingan 2 retirement/lay-up (- 148 MW) upon commencement of Maritime Link Base Block import (+ 153 MW)
[51] Tidal projects (firm capacity) forecast to be phased-in over the 10 years..
[52] Assumes ELCC 95% for hydro sites. Mersey is derated by 6.8 MW during anticipated rebuild work, refer to Section 3.1.2. Wreck Cove life extension modifications assumes one WC unit will be unavailable from June 2022 to July 2024, refer to Section 3.1.3. Solutions for any capacity shortfalls will be evaluated including access to firm capacity if required.
[53] Additions and Retirements as per the 2020 IRP Reference Plan (2.0C) shown in Section 3.2.1, Figure 6.

8.0 TRANSMISSION PLANNING

8.1 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 2021



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 tie that was placed into service on January 15, 2018 in preparation for the receipt of capacity and energy from the Muskrat Falls Hydro project and the Labrador Island Link DC tie between Labrador and Newfoundland. The Maritime Link is owned and operated by NSP Maritime Link Inc., a wholly owned subsidiary of Emera Newfoundland & Labrador.

8.2 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.

8.2.1 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).

8.2.2 Bulk Electric System (BES)

The NERC Bulk Electric 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.[54]

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.

8.2.3 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 also 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.

8.2.4 NPCC Directory 1 Review

A Working Group under the NPCC Task Forces on Coordination of Planning (TFCP) and Coordination of Operation (TFCO) has been created to conduct a review of the NPCC Directory 1 Document: Design and Operation of the Bulk Power System.

[54] M06930, Nova Scotia Power Application for Approval of the NERC Bulk Electric System (BES) definition, the NS Power BES Exception Procedure, the BES Exception Request Form and NS Power's specific requests for exceptions from the BES, NSUARB Order, April 6, 2017.

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[55] 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. The objectives of the review are stated as follows:

> In accordance with the NPCC Directory Review and Revision Manual perform the periodic review of NPCC Directory #1 Design and Operation of the Bulk Power System. Considering the differing performance requirements and objectives of the NPCC criteria and NERC reliability standards, this review will:
>
> 1. Review landscape of Directory #1 related NERC reliability standards with focus on upcoming or proposed standard changes; e.g. "Establish and Communicate SOL Projects."
>
> 2. Review of Directory #1 related NERC standards and:
>
>   a. Assess incremental value of Directory #1 over NERC standards
>
>   b. Determine if revision(s) to NERC standards may support North American BES reliability and notify the Regional Standards Committee.
>
> 3. Review Directory#1 operating criteria to ensure consistency with NERC IROL and SOL requirements & terminology.
>
> 4. Identify any required changes based on increased penetration of distributed energy resources ("DER") or unnecessary obstacles to the reliable deployment of DER.
>
> 5. Perform a cost effectiveness review on the planning and operating criteria in Directory#1 to identify potential alternatives that achieve the same reliability outcome.
>
> 6. Consider any NERC continent-wide efforts (e.g. SPIDERWG) to verify that proposed Directory #1 revisions align with those efforts.

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

7. Consider and propose alternatives to the terms “significant adverse impact”, “local area”, and “small or radial portions of the system” in performance requirements for the contingencies of Table 1 and Table 3 that better align with NERC terminology and concepts.

8. Update Directory #1 to reflect the term Remedial Action Scheme (“RAS”), rather than Special Protection System (“SPS”).

9. Review Directory #1, R12 and consider clarification of when the application of a RAS is not an acceptable solution to meet system performance requirements.

10. Resolve Directory 1 and Directory 7 references to “applicable criteria.” Directory 1 could describe what is meant by “applicable criteria”, as noted in multiple spots in the revised Directory 7, or Directory 7 could replace “applicable criteria” with a more general reference to facilitating achievement of the intended performance outcome.

11. Consider whether specific guidance on loop flow assumptions need to be considered when establishing base cases and the associated transfers.

12. Review guidelines in Directory #1 Appendix B for consistency with Area Transmission Review presentation formats.

13. Consider mechanisms to enhance communication between Operations and Planning.

14. Consider the impact of increasing amounts of Variable Energy Resources (“VER”), e.g. wind and solar generation. Determine if there are obstacles or more effective and reliable approaches to VER deployment.

15. Ensure NPCC is not inhibiting the State and Provincial decarbonization goals while meeting reliability and resilience objectives.

16. Review relevance of Directory #1 appendices content.

NS Power has representation from both Operations and Planning on the Directory 1 Working Group that is performing the review. At this time, the Directory 1 Working Group anticipates the review will take approximately two years to complete.

8.3 Transmission Life Extension

NS Power has in place a comprehensive maintenance program on 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:

- 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 will replace 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.

8.4 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 subjected 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.

8.5 New Large load Customer Interconnection Requests

NS Power received a number of new large load requests in 2020 with respect to proposed commercial, mining, aquaculture and government projects ranging in size from 1-15 MVA. As a result, approximately 45 Preliminary Assessments were performed, leading to the completion of eight formal Load Impact Studies on both the transmission and distribution systems. Five Load Impact studies are also either in progress or yet to be initiated. In two 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.

There have been five applications to serve new or upgraded hospital facilities. These facilities are now requiring two distribution feeder supplies, each fed from a different substation. Both supplies must be capable of feeding the entire hospital load. Under normal conditions, each feeder circuit carries approximately 50 percent of the load. Upon loss of one source, the load supplied by that circuit automatically transfers to the second circuit. Where an existing distribution feeder circuit supply exists, NS Power has assumed responsibility for system upgrades for the primary supply to the facility. However, the facilities are responsible for the full cost of the second supply and all system upgrades required to provide that supply.

9.0 TRANSMISSION DEVELOPMENT 2020 TO 2030

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.

9.1 Impact of Proposed Load Facilities

As noted in Section 8.5 of this Report, there are a number of system upgrades required to serve load facilities greater than 1 MW that were proposed in 2019 and 2020. These projects have precipitated the need for the following system upgrades:

1. Construction of new 15/20/25 MVA, 138 kV-26 kV substation at 101W-Bowater. This substation is currently under construction with an expected completion date in 2022.
2. Advancement of upgrades to 69 kV line L-5021 supplying the 50V-Klondike Substation. The temperature rating of L-5021 was upgraded to 70°C in 2020.
3. Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in 2020/21. The design of this substation is currently in progress.
4. Replacement of the 15N-Willow Lane 15/20/25//28 MVA, 69 kV-25 kV transformer 15N-T3 in 2020/21. A replacement transformer was ordered in 2020 and is scheduled to be installed in 2021.
5. Replacement of the Trenton 15/20/25 MVA, 69 kV-25 kV transformer 50N-T63 in 2020/21. A replacement transformer was ordered in 2020 and is scheduled to be installed in 2021.

6. Installation of a second 25/33/42 MVA, 138 kV-25 kV transformer at 1N-Onslow in 2022. Area load continues to be monitored to determine the appropriate timing of this installation.

7. Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Suzie Lake Crescent in 2023. Property acquisition for this site is currently underway.

8. Installation of a new 10MVA, 69-25 kV portable dead-front transformer on line L-5510 required to provide a 25 kV supply to a new mine site in 2022/23.

9. Refurbishment of the 6S-Terrace Street Substation following retirement of 4kV source with a new 7.5/10/12.5 MVA, 69-12.5 kV transformer complete with two new 12.5 kV feeder circuits in 2022/23 to accommodate reliability in the Sydney area and to provide a second source to the Cape Breton Regional Hospital (CBRH) facility. A capital contribution will be required of the CBRH for this work.

9.2 129H-Kearney Lake Relocation

In the 2020 10-Year System Outlook Report, NS Power reported the lease for the 129H Kearney Lake Road substation property had been extended on February 27, 2018 and was set to expire on December 31, 2022. NS Power had been advised that the property owner intended to develop the site and that further lease extensions. As such, NS Power planned to relocate the 129H-Substation from its present site to two land parcels located across the street which were purchased for this purpose in 1986 and 1988.

Detailed inspection of these two land parcels revealed that site development costs would 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 the Company acquiring an 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 also prepared to extend the existing lease if required in order to complete this option. This option also involves surrendering a small portion of the existing L-6038 right-of-way resulting in re-alignment of the 129H transmission approaches so that L-6038 will be in the same corridor as the existing L-5004.

As a result of this new option, NS Power has suspended plans to build a new 129H Kearney Lake substation, and instead is developing a scope of work to remain at the existing site.

9.3 Transmission Development Plans

Transmission development plans are summarized below. As noted above, these projects are subject to change. The majority of the projects listed are included in the 2021 Annual Capital Expenditure Plan. In addition, some of the timelines associated with the projects listed in 2021 continue to be impacted by the ongoing COVID-19 global pandemic.

2021

- Complete 12 MVA Mount Hope 69 kV-25 kV substation in Dartmouth (carry-over from 2020).
- 5P 25 MVA Mobile Substation Replacement (carry-over from 2020).
- 101W-Port Mersey Expansion to include a new 138 kV-25 kV, 15/20/25 MVA transformer and two feeders (C0011261, carry-over from 2020).
- Deteriorated Transmission Structure replacements and upgrades (L-6539, L-6516, L-6020, L-5054)
- Replacement of 9W-B53 support structure (carry-over from 2020).
- Construction of a new 25/33/42 MVA, 138 kV-25 kV substation in Stellarton in 2021/22.
- Replacement of the 15N-Willow Lane 15/20/25//28 MVA, 69 kV-25 kV transformer 15N-T3 in 2021.

- Replacement of the Trenton 15/20/25 MVA, 69 kV-25 kV transformer 50N-T63 in 2021.
- Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 6 of 8).
- Procure the existing 129H-Kearney Lake Substation site from existing property owner in exchange for NS Power property on the other side of Kearney Lake Road in 2021.

2022

- 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 7 of 8).
- Install New 138 kV Supply to 50V-Klondike and replace existing 69-25 kV transformer with new 15/20/25 MVA unit.

2023

- Installation of a new 25/33/42 MVA, 138 kV-25 kV substation on Suzie Lake.
- Transmission Right-of-Way Widening 69 kV to reduce the occurrence of edge and off right-of-way tree contacts (Year 8 of 8).

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 Stellarton substation.

2028

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

9.4 Western Valley Transmission System – Phase II Study

A study was initiated in late 2017 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 is to assess the following five 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 69kV)

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

Status: Work on the Western Valley Transmission System – Phase II Study is anticipated to be be completed by early Q3 2021.

10.0 PANDEMIC RESPONSE

As a result of the response to the COVID-19 global pandemic, Nova Scotia Power has experienced slight shifts in the timing and ramping of peak load. The impacts on load continue, with an increase in residential load and a decrease in commercial load compared to prior years as a result of the pandemic. Weather remains the main driver of load profiles. The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated as the situation unfolds.

NS Power has created and enacted system operator contingency plans to ensure health and safety of personnel and continued reliable operation of the power grid. The Company is evaluating contingency plans for T&D and Generation planned work, planned maintenance, and forced outages to proceed conservatively while mitigating short-term and longer term reliability risks. Contingency plans have continued to be evaluated over the course of the pandemic.

NS Power continues to monitor the ongoing spread of COVID-19 and remains focused on the health and safety of employees, consultants, contractors, and their families. A response team is monitoring the situation, coordinating with authorities, and keeping employees informed via regular business updates.

11.0 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 have driven and will continue to drive transformation of the NS Power electric power system.

As discussed in Section 10.0 above, NS Power continues to monitor the ongoing spread of COVID-19 and the impacts of the pandemic.

The Company is currently forecasting a capacity deficit from 2022 until 2024. Solutions for any capacity shortfalls will be evaluated, including access to firm capacity if required. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will adjust decisions accordingly.

The key inputs for Transmission Planning in the 10-year window of this report include the impact of proposed new load facilities outlined in Section 9.1, transmission of energy to be delivered over the Maritime Link, and continued compliance with Reliability Standards.

The 2020 IRP evaluated a robust set of future planning scenarios, with modeling assumptions that were created with comprehensive stakeholder input. Section 7.2 provides the detailed analysis of the PRM assumption that was evaluated in the 2020 IRP. As discussed in Section 7.3 the 2020 IRP evaluation has provided an updated ELCC for existing and new wind. The reference plan from the 2020 IRP (Scenario 2.0C) forms the planning basis for the 2021 10-Year System Outlook and is the reference for the current Steam Fleet Retirement schedule as shown in Section 3.2.1, the current Unit Utilization and Investment Strategey as discussed in Section 3.3 and the foundation for the Load and Resources Review found in Section 7.4. For energy forecasting purposes, updated PLEXOS modeling for the inital three years 2022-2024 was completed and the reference plan from the 2020 IRP (Scenario 2.0C) provides the data for the period of 2025-2031.

Given the recent announcements by the Federal Government of its intention to cease all coal-fired electricity generation by 2030 and to increase the cost of GHG emissions by increasing the carbon price, as well as the announcement by the Government of Nova Scotia to implement a renewable energy standard of 80 percent it is anticipated that NS Power will experience significant changes over the 10-year period considered in this report.

As these changes are better understood through legislative and regulation changes, these changes will be used inform future 10-Year System Outlook Reports and related long-term planning processes.