Nova Scotia Utility and Review Board

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

Nova Scotia Power
10 Year System Outlook

2017 Report

June 30, 2017

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1.0 INTRODUCTION

In accordance with the 3.4.2.1[1] Market Rule requirements and the direction provided in Nova Scotia Utility and Review Board's (Board, UARB) letter dated February 9, 2017,[2] this report provides NS Power's Ten Year System Outlook on behalf of the NS Power System Operator (NSPSO) for 2017.

In its letter of February 9, 2017, the UARB provided its comments on Nova Scotia Power's (NS Power, Company) 2016 10 Year System Outlook Report. The Board's comments referenced items including the capacity contribution of wind resources (including ERIS facilities), low forecasted capacity factors of existing generating plants, thermal plant utilization and retirement plans, sustaining capital investments and the level of renewable energy.

As agreed in the FAM Audit Settlement Agreement and as directed in the Board's letter, NS Power held a technical conference on April 13, 2017 regarding these matters. Subsequently, the UARB advised by letter dated May 5, 2017[3] that it will be engaging a consultant, Synapse Energy Economics Inc., to undertake an independent analysis of optimal utilization of generation resources. The impact, if any, of the outcome of this process on the Company's current plan is unknown and therefore not commented upon in this report.

Accordingly, the 2017 10 Year System Outlook report contains the following information:

[1] 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).

[2] M07540, Letter, UARB to NS Power, February 9, 2017.

[3] M08059, Letter, UARB to NS Power, May 5, 2017.

- A summary of the NS Power load forecast and update on the Demand Side Management (DSM) forecast in Sections 2-3.

- A summary of generation expansion anticipated for facilities owned by NS Power and others in Sections 4-6, including an updated Unit Utilization and Investment Strategy in Section 4.3.

- A summary of environmental and emissions regulatory requirements, as well as forecast compliance in Section 7. This section also includes clarification of the level of renewable energy available.

- An updated Resource Adequacy Assessment in Section 8, including the updated results of the annual Loss of Load Expectation for wind capacity value in Section 8.3.

- A discussion of transmission planning issues in Section 9.

- Identification of transmission related capital projects currently in the Transmission Development Plan in Sections 10 and 11.

2.0 LOAD FORECAST

The NS Power load forecast provides an outlook on the energy and peak demand requirements of in-province customers. 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 UARB in the 2017 Load Forecast Report on May 31, 2017[4] 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 a Net System Requirement (NSR, which is in-province sales plus associated losses, net of exports and station service).

Figure 1 shows historical and forecast net annual energy requirements. Anticipated growth is expected to be partially offset by DSM initiatives. After accounting for the effects of DSM savings, NSR is expected to remain flat over the forecast period (2017-2027).

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 in each year.

[4] M08087, Exhibit N-1, NS Power 2017 Load Forecast Report, May 31, 2017

Figure 1: Total Energy Requirement with Future DSM Program Effects

Year	Total Energy (GWh)	Growth (%)
2007	12,638	15.5%
2008	12,539	-0.8%
2009	12,073	-3.7%
2010	12,158	0.7%
2011	11,907	-2.1%
2012	10,475	-12.0% (Note 1)
2013	11,194	6.9%
2014	11,037	-1.4%
2015	11,098	0.5%
2016	10,809	-2.6%
2017*	10,914	1.0%
2018*	10,987	0.7%
2019*	10,952	-0.3%
2020*	10,976	0.2%
2021*	10,947	-0.3%
2022*	10,958	0.1%
2023*	10,983	0.2%
2024*	11,010	0.2%
2025*	10,980	-0.3%
2026*	10,958	-0.2%
2027*	10,967	0.1%

***** Values for 2017-2027 are forecasts
Note 1: This variance was mainly due to warm weather and loss of 2 large industrial customers.

The peak forecast is developed from 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. After accounting for the effects of DSM savings, total system peak is expected to increase 0.6 percent annually over the forecast period. **Figure 2** shows the historical and forecast net system peak.

Figure 2: Coincident Peak Demand with Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Firm Contribution to Peak (MW)	System Peak (MW)	Growth (%)
2007	381	1,774	2,154	3.3%
2008	352	1,840	2,192	1.7%
2009	268	1,824	2,092	-4.5%
2010	295	1,820	2,114	1.0%
2011	265	1,903	2,168	2.5%
2012	141	1,740	1,882	-13.2% (Note 1)
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*	151	1,960	2,110	0.0%
2018*	156	1,993	2,149	1.8%
2019*	156	2,010	2,166	0.8%
2020*	155	2,029	2,184	0.8%
2021*	155	2,038	2,193	0.4%
2022*	155	2,054	2,208	0.7%
2023*	154	2,073	2,227	0.8%
2024*	154	2,080	2,234	0.3%
2025*	154	2,084	2,238	0.2%
2026*	153	2,082	2,236	-0.1%
2027*	153	2,086	2,239	0.1%

*Forecasted value
Note1. This variance was due to warm weather and the closure of 2 large industrial customers.

3.0 DEMAND SIDE MANAGEMENT FORECAST

DSM and conservation plans continue to play a role in the use of electricity in Nova Scotia. DSM is taken into account in the load forecast by adjusting the forecast for DSM savings. NS Power uses the DSM targets approved by the Board to modify its load and demand forecasts. In August 2015, the Board approved a DSM plan covering the 2016–2018 period. The DSM savings below reflect the levels approved by the Board.

2019 DSM savings are held equal to 2018 levels in order to best align with Section 20 of the *Electricity Plan Implementation (2015) Act* which caps DSM spending for the calendar year 2019 at an amount not greater than $34,050,000. Beyond 2019, DSM savings equal the base DSM scenario from the 2014 Integrated Resource Plan (IRP).

The base DSM scenario was chosen as the 2021 – 2026 DSM forecast because the average annual savings in the base DSM forecast best match the expected average annual DSM savings from the 2016 to 2019 period.

One of the challenges with integrating DSM into the load forecast is the fact that past DSM has an influence on many inputs to the load forecast, including sales, price, and overall appliance efficiency. Since the inputs to the regression model are impacted by DSM, the model output is potentially lower than it would be if the inputs had not been impacted by DSM. Subtracting 100 percent of any future DSM savings from the load forecast results in double counting the impact of such DSM savings because even without counting future DSM programs, the forecast model has some level of DSM savings inherent in the underlying data and therefore is already on a lower trajectory.

In general, the efficiency of appliances used by consumers is improving as a result of several factors, including past investment in DSM, competition among manufacturers inducing technical improvements in appliance efficiency, consumer awareness of environmental issues, a cultural shift to making energy efficient behaviour the norm, and consumers' awareness of the long term costs savings associated with energy efficient products. The outcome of the incentive setting methodology proceeding for DSM (E-ENS-R-16, M07544) may impact future DSM targets. NS Power and its consultant, The Brattle Group, filed the following comment in response to EfficiencyOne's most current incentive setting methodology study on April 27, 2017.

> 4- The CLEAResult report acknowledges that customers are able to take advantage of other financial incentives including manufacturer rebates and government tax credits, if available, in addition to ratepayer-funded incentives. If ENS channels some of their customer education and supply chain efforts on putting customers in touch with other rebate opportunities, this could help reduce the overall amount of ratepayer-funded incentives.[5]

NS Power worked with its forecasting consultant, Itron, to statistically determine what level of DSM is already captured in the load forecast and found that 40-50 percent of forecast DSM savings are already accounted for in the base forecast produced by the model. Further details on this analysis can be found in NS Power's 2017 10 Year Load Forecast report.

Figure 3 summarizes annual projected demand and energy savings from efficiency programming included in NS Power's Load Forecast in Section 4.0.

Figure 3: Annual Forecast DSM Savings and Load Forecast Modifying GWh

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial and Industrial DSM savings (GWh)	DSM Adjustment for Residential Load Forecast (GWh)	DSM Adjustment for Commercial and Industrial Load Forecast (GWh)
2017	59.8	76.7	36.2	36.5
2018	59.3	76.6	35.9	36.5
2019	59.3	76.6	35.9	36.5

[5] EfficiencyOne (E1) - Incentive Setting Methodology, M07544, NSPI Comments, NSPI-NSUARB, April 27, 2017, Appendix A, page 3.

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial and Industrial DSM savings (GWh)	DSM Adjustment for Residential Load Forecast (GWh)	DSM Adjustment for Commercial and Industrial Load Forecast (GWh)
2020	57.7	76.2	34.9	36.3
2021	56.0	74.1	33.9	35.3
2022	54.9	72.7	33.3	34.6
2023	54.5	72.1	33.0	34.3
2024	54.9	72.5	33.2	34.5
2025	56.0	74.1	33.9	35.3
2026	58.4	77.2	35.4	36.8
2027	61.8	81.7	37.4	38.9

4.0 GENERATION RESOURCES

4.1 Existing Generation Resources

Nova Scotia's generation portfolio is composed of a mix of fuel and technology types that includes coal, petroleum coke, light and heavy oil, natural gas, biomass, wind, tidal 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.

Figure 4 lists NS Power's and IPPs verified and forecasted firm generating capability for generating stations/systems along with their fuel types. It has been updated to include changes and additions effective up to the filing date of this report, discussed further in Section 4.1.1.

Figure 4: 2017 Firm Generating Capability for NS Power and IPPs

Facility	Fuel Type	Winter Net Capacity (MW)
Avon	Hydro	6.8
Black River	Hydro	22.5
Lequille System (Lequille, Nictaux, Paradise)	Hydro	24.2
Bear River System (Bear/Weymouth/Sissiboo)	Hydro	37.4
Roseway/Harmony[6]	Hydro	0.0
Tusket	Hydro	2.4
Mersey System	Hydro	42.5
St. Margaret's Bay	Hydro	10.8
Sheet Harbour	Hydro	10.8
Dickie Brook	Hydro	3.8
Wreck Cove	Hydro	212.0

[6] The timing of the return to service of the Roseway portion of the Roseway/Harmony system is pending decisions with regards to level of refurbishment.

Facility	Fuel Type	Winter Net Capacity (MW)
Annapolis Tidal[7]	Hydro	3.5
Fall River	Hydro	0.5
Total Hydro		**377.1**
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	612
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	168
Total Steam		**1552**
Tufts Cove Units 4,5 & 6	Natural Gas	144
Total Combined Cycle		**144**
Burnside (1, 2, 3)[8]	Light Fuel Oil	99
Tusket	Light Fuel Oil	33
Victoria Junction (1, 2)	Light Fuel Oil	66
Total Combustion Turbine		**198**
Pre-2001 Renewables	IPPs	25.8
Post-2001Renewables (firm)[9]	IPPs	44.7
NS Power wind (firm)[9]	Wind	5.1
Community-Feed-in-Tariff (firm)[9]	IPPs	27.6
Tidal Feed-in-Tariff (firm)	IPPs	0.4
Total IPPs & Renewables		**103.7**
Total Capacity		**2374.8**

[7] The capacity of the Annapolis Tidal unit is based on average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.5 MW.

[8] Burnside Unit #4 (winter capacity of 33 MW) is presently unavailable but is planned to be returned to service in the winter of 2017/2018.

[9] The firm capacity value assumed for wind depends on the type of interconnection service. Energy Resource Interconnection Service (ERIS) projects have a firm capacity assumption of zero, consistent with the Generation Interconnection Procedures (GIP). These projects may not possess one or more of the physical characteristics required in order to provide capacity service. Network Resource Interconnection Service (NRIS) projects are considered firm for capacity planning because they possess the necessary physical characteristics and transmission capacity to ensure full operation in all hours of the year.

4.1.1 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 *NPCC Regional Reliability Reference Directory #9, Generator Real Power Verification.*[10] These Criteria are reviewed and adjusted periodically by NPCC and subject to approval by the UARB.

To comply with this requirement, during 2017 NS Power conducted maximum capacity verification testing. The firm capacity of some units has been adjusted to reflect the results of the verification testing as well as operational conditions. The adjustments made are shown in **Figure 5** below:

Figure 5: Net Operating Capacity Adjustments

	2016 10 Year System Outlook Capacity (MW)	**2017 10 Year System Outlook Capacity (MW)**
Lingan 3	158	153
Point Aconi	171	168
Point Tupper	152	150
Trenton 6	157	154
Tufts Cove 1	81	78
Tufts Cove 6	49	46
PHBM	45	43
Burnside 1	30	33
Burnside 2	30	33
Burnside 3	30	33
Burnside 4	30	33
Tusket	30	33[11]
VJ 1	30	33
VJ 2	30	33

[10] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx
[11] This rating is currently used for planning purposes. Permit adjustments are ongoing.

NS Power will continue to refresh unit maximum capacities in the 10 Year System Outlook each year as operational conditions change.

4.2 Changes in Capacity

Figure 6 provides the firm Supply and DSM capacity changes in accordance with the assumption set developed for the Base Cost of Fuel forecast and the 2017 Load Forecast.

Figure 6: Firm Capacity Changes & DSM

New Resources 2017-2026	Net MW
DSM firm	141
Community Feed-in Tariff (Firm)	19
Tidal Feed-in Tariff (Firm capacity)	2
Biomass [12]	43
Maritime Link Import - Base Block	153
Burnside #4 (return to service)	33
Assumed Unit Retirements/Lay-ups [13]	-153
Net Firm Supply & Demand MW Change Projected Over Planning Period	**238**

4.2.1 Burnside Combustion Turbine Unit #4

Burnside Unit #4 is a 33 MW[14] combustion turbine located in the Burnside Industrial Park in Dartmouth that provides black start capability, 10 minute reserve, dynamic reactive reserve, reactive power support and firm capacity to the NS Power electrical system. Unit #4 was originally commissioned in 1972 but has been out of service since 2008.

[12] The transmission upgrades being completed for the Maritime Link will allow 45MW of the PH Biomass unit to be counted as firm; however, tests for operating capacity completed have resulted in 43MW of available firm capacity able to be credited.
[13] Retirement of Lingan 2 unit once Maritime Link Base Block provides firm capacity service.
[14] As discussed in Section 4.2.1, after completion of unit capacity testing in 2017, Burnside Unit #4 has been updated to 33MW at an ambient temperature of -12 degrees C. In the 2016 10 Year System Outlook the maximum capacity was stated as 30 MW.

In its letter dated March 31, 2016, the Board approved CI 33142 CT - Burnside Unit #4 Restoration, and provided the following:

> The approval of this project in the requested amount is subject to the following conditions:
>
> 1. Actively investigate energy storage technology options and consider them as a viable alternative to future investment in NSPI's combustion turbine fleet or to new thermal fast-acting generation;
>
> 2. Develop models to estimate costs and benefits of fast-acting generation and energy storage technologies. These models should include all operating costs as well as capital costs for different sized units; and
>
> 3. Update the Board and Stakeholders on the results of NSP's investigation of storage technology as part of the 2017 ACE Plan filing.[15]

NS Power is currently forecasting an expected return to service for Burnside Unit #4 by the end of 2017.

As directed by the Board in its March 31, 2016 letter, NS Power conducted a review of energy storage technologies and provided an update on this review in the 2017 ACE Plan.[16] NS Power's investigation concluded that storage solutions are not yet cost effective when compared to traditional transmission and power generation solutions and operational and performance issues are not fully understood. However, the Company expects the cost competitiveness of storage systems will improve as the technologies evolve over time, and is participating in several pilot projects to further assess the potential of these technologies as described in the ACE plan.

NS Power has filed its Intelligent Feeder Project with the UARB.[17] This project will see the installation of Powerwall technology in customer homes and Tesla Power Pack technology at an NS Power substation. The project will provide first had experience in

[15] M07156, Decision Letter, UARB to NS Power. March 31, 2016.
[16] M07745 – Nova Scotia Power Inc. 2017 Annual Capital Expenditure Plan, pages 155-157 of 1100.
[17] M07981, Exhibit N-1 Intelligent Feeder Project Capital Work Order 49787, March 31, 2017.

the operation of battery energy storage systems including asset performance and integration of control and dispatch.

4.2.2 Mersey Hydro

NS Power is in the process of evaluating redevelopment options for the Mersey Hydro system. Degradation of the powerhouse and water control structures after nearly a century of service for some hydro assets 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 hydroelectric production. Redevelopment options under consideration include replacement as is (42.5 MW) or an increase in the installed capacity of the system to 75 MW.

4.2.3 Firm Capacity of Distributed Generation

A portion of distributed generation has been denoted as firm – these sources are listed in **Figure 4** and **Figure 6** above. Ongoing evaluation of the firm capacity contribution of these facilities is prudent to understand before this can be reliably designated as firm capacity, in accordance with NPCC Regional Reliability Reference Directory #9 (Verification of Generator Gross and Net Real Power Capability).[18] Future solar projects have not been included as firm generating capacity as they do not contribute to winter peak.

4.3 Unit Utilization & Investment Strategy

The following sub-sections provide an updated Unit Utilization and Investment Strategy (UUIS). The Company has extended its forecast in this report to include 10 years of utilization and investment projections. These projections are based on NS Power's currently available assumptions; forecasts will continuously change as assumptions are

[18] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

adjusted based on regulatory or policy changes, operational experience and market information.

This UUIS is a product of generation planning and engineering integrating the latest in Asset Management methodology and Generation Planning techniques in the service of a complex generation operation. It provides an outlook for how NS Power will operate and invest in generation assets recognizing the trend towards lower utilization along with demands for flexible operation arising from renewables integration, and will continue to be updated annually in the 10 Year System Outlook Report.

4.3.1 Projections of Unit Utilization

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 variable wind generation on previously base-loaded steam units. Therefore, it is necessary to also 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 forecasted unit capacity factors.

NS Power has created the concept of utilization factor (UF) for the purpose of communicating the operation strategy for a particular generator. The essence of this approach is to better express the demands placed upon NS Power's generating units given the planned utilization. The UF for each unit is evaluated by considering the forecasted 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 7**, below.

Figure 7: Utilization Factor

The UF parameters are assessed to more completely describe the operational outlook for the steam fleet and direct investment planning, and include:

- 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 can stress many failure mechanisms (e.g. turbines, motors, breakers, and fatigue in high energy piping systems); 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. 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 8 below provides the current forecasted unit utilization of NS Power's steam fleet.

Figure 8: NS Power Steam Fleet Unit Utilization Forecast

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Lingan 1	Capacity Factor (%)	28	31	28	25	29	25	22	15	26	18
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	25 - 50	25 - 50	10 - 25	25 - 50	10 - 25
	Service Hours	3343	3717	5050	4332	4919	4202	3784	2135	3740	2628
	Utilization Factor	MED	MED	MED	MED	MED	MED	MED	MED	MED	MED
Lingan 2	Capacity Factor (%)	25	24	48	0	0	0	0	0	0	0
	Unit Cycles (Ranges)	< 10	< 10	< 10	0	0	0	0	0	0	0
	Service Hours	2830	2695	1745	0	0	0	0	0	0	0
	Utilization Factor	LOW	LOW	LOW	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Lingan 3	Capacity Factor (%)	52	51	32	35	29	27	29	38	36	37
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	10 - 25	10 - 25
	Service Hours	6367	6045	5514	6001	4737	4343	4786	5064	5394	5244
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Lingan 4	Capacity Factor (%)	52	48	29	30	27	32	31	35	28	36
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	6706	5581	4657	5128	4546	5483	5375	5144	4168	5366
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Point Aconi	Capacity Factor (%)	85	84	66	62	64	66	74	78	79	79
	Unit Cycles (Ranges)	< 10	< 10	10 - 25	10 - 25	10 - 25	< 10	< 10	< 10	< 10	< 10
	Service Hours	7491	7512	6929	6459	6735	6827	7237	7372	7330	7284
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Point Tupper	Capacity Factor (%)	81	72	54	36	35	36	58	56	40	40
	Unit Cycles (Ranges)	< 10	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	25 - 50	25 - 50
	Service Hours	7944	7181	7238	4163	3987	4227	6886	6637	5176	4960
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Trenton 5	Capacity Factor (%)	32	29	19	22	26	30	22	1	1	1
	Unit Cycles (Ranges)	< 10	10 - 25	10 - 25	10 - 25	25 - 50	10 - 25	< 10	< 10	< 10	< 10
	Service Hours	3358	3180	2387	3181	3528	3942	2688	177	140	90
	Utilization Factor	MED	MED	MED	MED	MED	LOW	LOW	LOW	LOW	LOW
Trenton 6	Capacity Factor (%)	73	65	22	41	45	44	22	42	46	45
	Unit Cycles (Ranges)	< 10	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	< 10	10 - 25	10 - 25	10 - 25
	Service Hours	7122	6671	2965	6361	6943	6633	3036	4331	4837	4680
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	MED	MED	MED	MED	MED
Tufts Cove 1	Capacity Factor (%)	4	28	34	28	20	10	33	18	16	28
	Unit Cycles (Ranges)	< 10	< 10	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	< 10	< 10	10 - 25
	Service Hours	439	2716	3384	3140	2161	1119	3264	1727	1600	2740
	Utilization Factor	LOW	LOW	LOW	LOW	LOW	LOW	LOW	LOW	LOW	LOW
Tufts Cove 2	Capacity Factor (%)	35	41	51	28	37	38	50	60	62	59
	Unit Cycles (Ranges)	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	4311	4786	6206	3665	4894	4942	5763	6585	6753	6749
	Utilization Factor	MED	MED	MED	MED	MED	HIGH	HIGH	HIGH	HIGH	HIGH
Tufts Cove 3	Capacity Factor (%)	37	38	46	34	28	28	46	61	57	57
	Unit Cycles (Ranges)	25 - 50	25 - 50	25 - 50	50 - 100	25 - 50	50 - 100	25 - 50	25 - 50	25 - 50	25 - 50
	Service Hours	4223	3976	5017	4308	3384	3560	5124	6430	6108	6375
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Tufts Cove 4	Capacity Factor (%)	62	61	63	58	58	57	74	76	75	76
	Unit Cycles (Ranges)	50 - 100	> 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	25 - 50	25 - 50	25 - 50
	Service Hours	5651	5679	5975	5569	5528	5356	6705	6824	6782	6854
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Tufts Cove 5	Capacity Factor (%)	65	64	65	60	63	60	76	77	79	78
	Unit Cycles (Ranges)	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	25 - 50	25 - 50	25 - 50	25 - 50
	Service Hours	5960	5943	6103	5702	5883	5645	6875	6960	7084	7020
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH
Tufts Cove 6	Capacity Factor (%)	45	43	41	39	40	40	55	58	57	54
	Unit Cycles (Ranges)	25 - 50	50 - 100	25 - 50	25 - 50	25 - 50	25 - 50	10 - 25	10 - 25	10 - 25	10 - 25
	Service Hours	6454	6535	6142	6617	6479	6314	7474	7473	7545	7490
	Utilization Factor	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH	HIGH

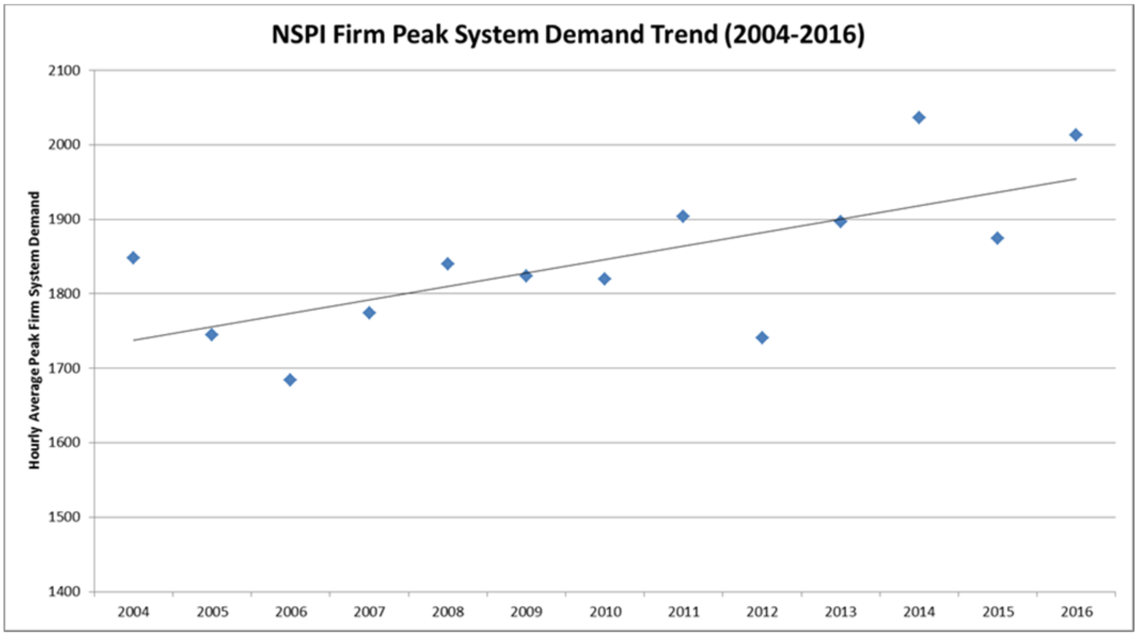
4.3.2 Steam Fleet Retirement Outlook

At present, NS Power is reviewing retirement options pertaining to its steam fleet. One exception is Lingan Unit #2, which will retire with the commissioning of the Maritime Link and the flow of the Nova Scotia Block of energy and related firm capacity. As demonstrated in the Load and Resources review, there is insufficient surplus capacity for a second retirement beyond Lingan Unit #2. Please refer to Section 8.5 and **Figure 24.**

As renewable electricity has been added to the generation mix to meet the requirements of the Renewable Electricity Regulations of the Province of Nova Scotia, the energy production from the steam fleet has diminished. However, the variable intermittent nature of much of the new renewable generation that has been added to the system means that much of it cannot be counted as firm generating capacity to meet firm peak demand and ensure adequate supply for customers.

As illustrated in **Figure 9** below, NS Power's firm peak demand has been increasing at a trend of one percent per year. While energy is increasingly being produced by new renewable sources, the required system demand is planned to be served by conventional steam capacity (together with CT's, hydro, and ML imports), in accordance with the reliability standard required by NERC/NPCC. Therefore, the retirement of steam units is not possible without replacement by equivalent firm capacity. NS Power understands the fleet retirement outlook may be explored further in the Generation Utilization & Optimization Process being initiated by the Board.

Figure 9: Peak System Demand Trend



As noted in the 2017 Load Forecast Report, NS Power continues to review and evolve the end-use forecasting methodology. Issues such as the interplay of inherent DSM and weather assumptions will continue to be evaluated to ensure forecast accuracy. NS Power will analyze and adjust its utilization and retirement strategy accordingly.

NS Power notes that the forecasted capacity factors for Tufts Cove Units #2 and #3 have increased since the 2016 10 Year System Outlook, as shown above in **Figure 8**. The unit utilization forecasts will vary based on input assumptions such as market energy prices and availability, fuel prices, load, and system constraints. As the Model optimizes dispatch against a set of input assumptions the forecasted utilization of the generating units can be expected to vary as inputs such as fuel pricing shift.

NS Power also continues to monitor developments in other jurisdictions related to coal generation and air emissions policy, as well as anticipated changes to the current federal Coal-Fired Electricity Generation Regulations and related provincial regulations, to assess potential fleet retirement implications.

4.3.3 Projections of Unit Sustaining Investment

Figure 11 and **Figure 12** below provide the projected sustaining investments based on the anticipated utilization forecast in Section 4.3.1. Estimates of unit sustaining investment are forecast by applying the UF. 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.

The overarching investment philosophy is to cost effectively maintain unit reliability while minimizing stranded capital. Mitigating risks by using less intensive investment strategies is a tactic executed throughout the thermal fleet. Major outage intervals are extended where possible to reduce large investments in the thermal fleet.

Major changes in the asset management plan from the 2016 10 Year System Outlook include:

- Increased cycling (output ramping or two shifting) of the thermal fleet can sustain the unit utilization factors even as the capacity factors decline. For example, a unit that is heavily cycled can require more sustaining investment than a base loaded machine. **Figure 10** shows the projected unit utilization factors.

- Higher forecasted utilization of Tuft's Cove driven by gas price forecasts, particularly Unit #2, results in the requirement for major investments to maintain unit reliability. This utilization forecast and the resultant necessary investment anticipated for Tuft's Cove Unit #2 is under further review, as alternatives such as operational restrictions or advancement of unit retirement and replacement will be considered.

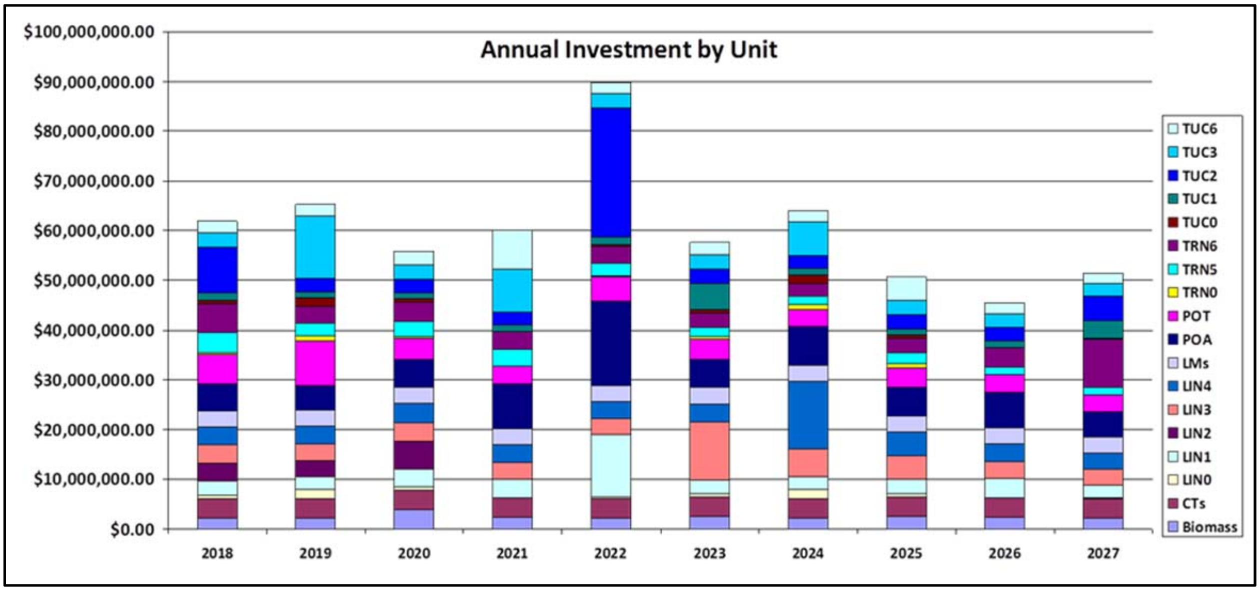
- Higher utilization forecasts for Lingan Unit #1 advances the need for a major outage into the 10 year planning window.

- Reduced utilization forecasts for Trenton Unit #5 extends the major outage interval beyond 2027.

Figure 10: Unit Utilization Factors

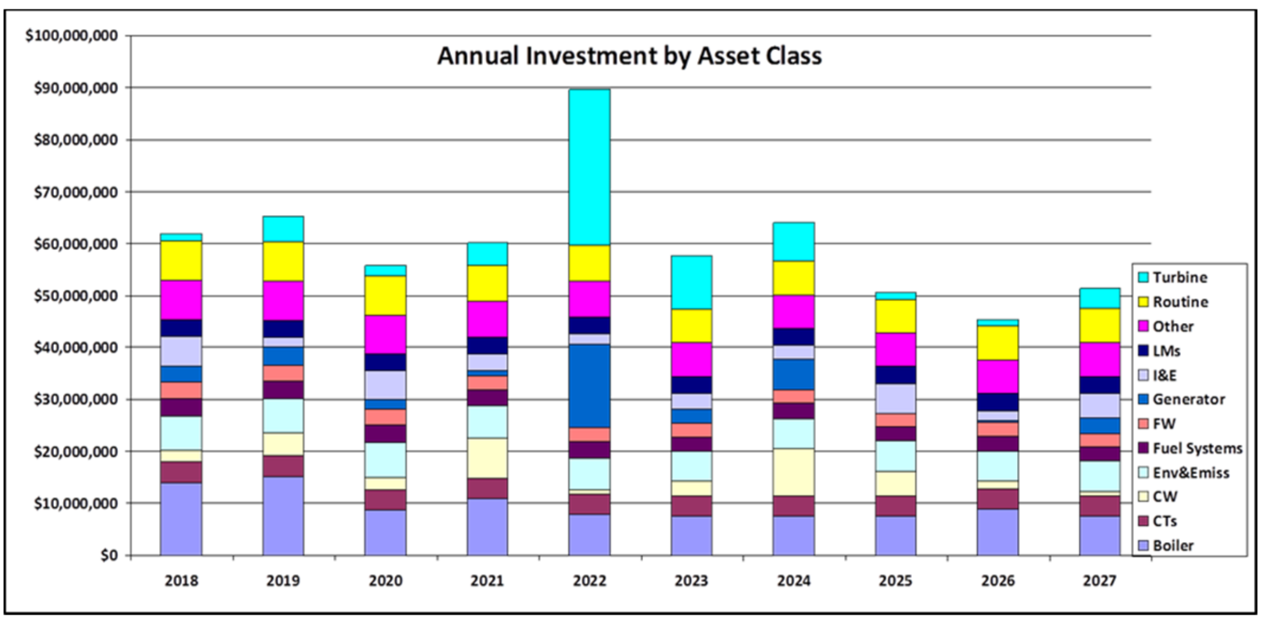
Unit	UF(2018-2022)	UF (2023-2027)
PH Biomass	HIGH	HIGH
Lingan Unit 1	MED	MED
Lingan Unit 2	LOW	OFF
Lingan Unit 3	HIGH	HIGH
Lingan Unit 4	HIGH	HIGH
Pt. Aconi	HIGH	HIGH
Pt. Tupper	HIGH	HIGH
Trenton 5	MED	LOW
Trenton 6	HIGH	MED
Tuft's Cove 1	LOW	LOW
Tuft's Cove 2	MED	HIGH
Tuft's Cove 3	HIGH	HIGH
Tuft's Cove 6	HIGH	HIGH
LM 6000	HIGH	HIGH
CT's	LOW	LOW

Figure 11: Forecasted Annual Investment (in 2017$) by Unit



Note: Figure does not include escalation as it is used for asset planning.

Figure 12: Forecasted Annual Investment (in 2017$) by Asset Class



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.

5.0 NEW SUPPLY SIDE FACILITIES

5.1 Potential New Facilities

As of May 30, 2017, NS Power has five Active Transmission Connected Interconnection Requests (72 MW) and eleven Active Distribution Connected Interconnection Requests (22.6 MW) at various stages of interconnection study.

Proponents of the transmission projects have requested Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). Distribution projects do not receive an NRIS or ERIS designation. 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 interconnection studies will be incorporated into future transmission plans.

6.0 QUEUED SYSTEM IMPACT STUDIES

Figure 13 provides NS Power's Advanced Stage Interconnection Queue.

Figure 13: Combined Transmission & Distribution Advanced Stage Interconnection Queue of June 27, 2017

Combined T/D Advanced Stage Interconnection Request Queue
Publish Date: Tuesday, June 27, 2017

Queue Order*	IR#	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point	Type	Inservice date DD-MMM-YY	Status	Service Type
1-T	426	27-Jul-12	Richmond	45.0	45.0	47C	Biomass	01-Jan-17	GIA Executed	NRIS
2-D	442	21-Dec-12	Hants	0.5	0.5	82V-423	Biogas	29-Dec-15	GIA Executed	N/A
3-T	507	5-Aug-14	Digby	2.0	2.0	77V-303	Tidal	04-Jun-16	GIA Executed	ERIS
4-D	503	3-Jun-14	Lunenburg	3.2	3.2	70W-321	Biomass	31-Aug-16	GIA Executed	N/A
5-D	489	4-Feb-14	Colchester	1.5	1.5	1N-421	Biomass	01-Jun-18	GIA Executed	N/A
6-D	498	23-Apr-14	Antigonish	0.5	0.5	4C-441	Biogas	15-Jan-15	GIA Executed	N/A
7-T	516	5-Dec-14	Cumberland	5.0	5.0	37N	Tidal	01-Jul-16	GIA Executed	NRIS
8-D	483	31-Dec-13	Hants	0.6	0.6	82V-401	Biogas	01-Aug-14	GIA Executed	N/A
9-D	459	8-Aug-13	Queens	3.6	3.6	50W-412	Wind	01-Jun-15	GIA Executed	N/A
10-D	518	16-Dec-14	Halifax	2.0	2.0	139H-411	Biomass	1-Oct-16	GIA Executed	N/A
11-D	522	9-Apr-15	Pictou	1.8	1.8	50N-410	Wind	30-Nov-16	GIA Executed	N/A
12-D	510	16-Sep-14	Cape Breton	2.4	2.4	82S-304	Wind	31-Dec-16	GIA Executed	N/A
13-T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	01-Jan-18	GIA Executed	NRIS
15-T	542	26-Sep-16	Cumberland	6.0	6.0	37N	Tidal	01-Jan-19	SIS in Progress	NRIS
16-D	553	24-Feb-17	Digby	0.9	0.9	509V-301	Tidal	31-Dec-18	SIS in Progress	N/A
17-D	557	19-Apr-17	Halifax	5.6	5.6		GRLF	01-Sep-18	SIS Milestones Met	N/A

All active transmission and distribution requests not appearing in the Combined Transmission & Distribution Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage, as they have not yet proceeded to the SIS stage of the Generator Interconnection Procedures (GIP). **Figure 14** indicates the location and size of the generating facilities currently in the Combined Transmission & Distribution Advanced Stage Interconnection Request Queue.

Figure 14: Generation Projects Currently in the Combined T/D Advanced Stage Interconnection Request Queue

Company/Location	Nameplate Capacity (MW)
IR #426 NRIS Version of existing 64MW (IR 219, which was ERIS) Biomass	N/A
IR #507 Tidal in Digby County	2
IR #516 Tidal in Cumberland County	5
IR #540 Wind in Hants County	14
IR #542 Tidal in Cumberland County	6
IR #557 Generation Replacement Load Following	6
COMFIT Distribution Interconnection Request	17
Total	**50**

The Port Hawkesbury Biomass 63.8 MW gross / 45 MW[19] net output generating unit is presently an ERIS classified resource which will be converted to NRIS following the system upgrades which are scheduled to take place in advance of the Maritime Link coming online.

6.1 OATT Transmission Service Queue

There is presently one request in the OATT Transmission Queue, as shown in **Figure 15.**

Figure 15: Requests in the OATT Transmission Queue

Number	Project	Date & Time of Service Request	Project Type	Project Location	Requested In-Service Date	Project size (MW)	Status
4	TSR 400	July 22, 2011	Point to Point	NS-NB	May 31, 2018	330	Application Complete – Participation Agreement is in the process of being signed

[19] As discussed in section 4.1.1, the rating of Port Hawkesbury Biomass generating unit has been modified to 43 MW to reflect the results of verification testing; however, at the time of the System Impact Study the rating was 45 MW.

7.0 ENVIRONMENTAL AND EMISSIONS REGULATORY REQUIREMENTS

7.1 Renewable Electricity Requirements

The Nova Scotia Renewable Electricity Standard (RES) includes a legislated renewable energy requirement of 25 percent of energy sales in 2015, and 40 percent in 2020.

In addition to these targets, 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.[20] 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 government 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. NS Power continues to have contractual obligations associated with operation and maintenance of this biomass cogeneration facility.

NS Power has complied with the legislated renewable energy requirement in 2015 and 2016 by serving 26.6 percent and 28 percent of sales respectively using qualifying renewable energy sources. NS Power's production tracking and forecast for the current year indicate that renewable energy compliance will also be achieved for the year 2017.

In its letter dated February 9, 2017 regarding the 2016 10 Year System Outlook Report, the UARB stated:

[20] Effective December 18, 2015, the Electricity Plan Implementation (2015) 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.

> In the SO Report, for the year 2020, NSPI reduced the amount of renewable energy contributed by its legacy hydro, the Maritime Link, and the Port Hawkesbury Biomass Plant ("PHBP") when compared to the levels noted in the 2015 report. Of particular note is that instead of identifying 1.2 TWh from the Maritime Link, NSPI reduced that amount to 906 GWh due to less "supplemental" energy. However, the 1.2 TWh was supposed to be the amount attributed to the Nova Scotia Block, not the supplemental component. Also, the amounts attributed to the PHBP has been reduced from 290/353 GWh (Port Hawkesbury Paper on/off) to 240/29 GWh. In its IR response, NSPI stated that it only counted the amount of renewable energy that was needed to satisfy the legislated requirements, not the total amount that is actually available from all resources. This understates the amount of renewable energy resources that NSPI has acquired to satisfy the legislated requirements.

NS Power notes that the total annual RES-eligible energy from the Maritime Link amounts to 1.2 TWh, which includes both the Nova Scotia Block and Supplemental Block (for the first 5 years of operation). Surplus energy purchases from the Maritime Link are not eligible as RES compliant in the Renewable Electricity Regulations. The level of RES compliance in 2020 may vary depending on the start date of the flow of the Nova Scotia Block and Supplemental Block on the Maritime Link; the 906 GWh level forecasted in last year's report represented a conservative estimate of delay in the flow of energy from the Supplemental Block. This year's forecast assumes a start date for both the Nova Scotia Block and Supplemental Block energy flow of January 1, 2020.

In accordance with the Board's statement above, this year's RES Compliance Forecast assumes a full year of Nova Scotia Block and Supplemental Block energy flow (1154GWh), as well as a fully dispatched biomass unit (290GWh), in order to illustrate the currently forecasted full amount of RES-eligible energy available to the Company. **Figure 16** below provides this forecast RES compliance for 2018 and 2020, when the required renewable energy level increases to 40 percent.

Figure 16: RES 2018 and 2020 Compliance Forecast

RES 2018 and 2020 Compliance Forecast			
	2018	**2020 with PHP**	**2020 no PHP**[21]
Energy Requirements (GWh) [22]			
NSR including DSM effects	10,987	10,976	9,896
Losses	723	703	703
Sales	10,264	10,273	9,193
RES (%) Requirement	25%	40%	40%
RES Requirement (GWh)	**2,566**	**4,109**	**3,677**
Renewable Energy Sources (GWh)			
NSPI Wind	260	260	260
Post 2001 IPPs	752	754	754
PH Biomass	290	290	290
COMFIT Wind Energy	491	503	503
COMFIT Non-Wind Energy	105	162	162
Eligible Pre 2001 IPPs	73	73	73
Eligible NSPI Legacy Hydro	961	939	939
REA procurement (South Canoe/Sable)	355	355	355
Maritime Link	0	1,154	1,154
Forecasted Renewable Energy (GWh)	**3,287**	**4,489**	**4,489**
Forecasted Surplus or Deficit (GWh)	**721**	**380**	**812**
Forecasted RES Percentage of Sales	**32.0%**	**43.7%**	**48.8%**

7.2 Environmental Regulatory Requirements

The Nova Scotia Greenhouse Gas Emissions Regulations specify emission caps for the period 2010 – 2030 as outlined in **Figure 17.** 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

[21] The Port Hawkesbury Paper Mill is approved to operate under a Load Retention Tariff until the end of 2019. As such, the compliance forecast figures are shown both inclusive and exclusive of the PHP customer load.
[22] NSR and Losses are from the 2017 NS Power 10 Year Energy and Demand Forecast, M08087, Exhibit N-1, Table A-1, May 31, 2017.

production of electricity in 2030 will have decreased by 58 percent from 2005 levels. The primary means of meeting the caps is a reduction in thermal generation from the existing coal-fired generating units, displaced by renewable energy.

Figure 17: Compliance CO_2 Emission Caps

Compliance Period	Calendar Years	Emission Cap for All Facilities (million tonnes CO_{2eq})
1	2010, 2011	19.22
2	2012, 2013	18.50
3	2014, 2015, 2016	26.32
4	2017, 2018, 2019	24.06
5	2020	7.50
6	2021, 2022, 2023, 2024	27.50
7	2025	6.0
8	2026, 2027, 2028, 2029	21.50
9	2030	4.50

The Nova Scotia Air Quality Regulations[23] specify emission caps for sulphur dioxide (SO_2), nitrogen oxides (NO_X), and mercury (Hg). These regulations were subsequently 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 as outlined in **Figure 18.** The regulations also provide local annual maximums, as well as limits on individual coal units for SO_2, as provided in **Figure 19** and **Figure 20** respectively. The mercury emission caps are outlined in **Figure 21.**

[23] http://novascotia.ca/just/regulations/regs/envairqt.htm

Figure 18: Emissions Multi-Year Caps (SO_2, NO_X)

Multi-Year Caps Period	SO_2 (t)	NO_X (t)
2015 – 2019 (equal outcome)	304,500	96,140
2020	36,250	14,955
2021 – 2024	136,000	56,000
2025	28,000	11,500
2026 – 2029	104,000	44,000
2030	20,000	8,800

Figure 19: Emissions Annual Maximums (SO_2, NO_X)[24]

Year	SO_2 Annual Maximum (t)	NO_X Annual Maximum (t)
2015 – 2019	72,500	21,365
2021 – 2024	36,250	14,955
2026 – 2029	28,000	11,500

Figure 20: Individual Unit Limits (SO_2)

Year	SO_2 Individual Unit Limit (t)
2015 – 2019	42,775
2020 – 2024	17,760
2025 – 2029	13,720
2030	9,800

[24] Annual maximums apply to the multi-year ranges from **Figure 19** only. Please refer to Figure 18 for the caps on years that are not contained within the multi-year cap ranges.

Figure 21: Mercury Emissions Caps

Year	Hg Emission Cap (kg)
2010	110
2011	100
2013	85
2014	65
2020	35
2030	30

By 2030, emissions of sulphur dioxide from generating electricity will have been reduced by 80 percent from 2005 levels. Nitrogen oxides 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.

The amendments to the Nova Scotia Air Quality Regulations[25] also provide an optional program until the end of 2020, through which NS Power can make up deferred mercury emission requirements from earlier in the decade. NS Power offers a mercury recovery program, such as recycling light bulbs or other mercury-containing consumer products, which reduces the amount of mercury going into the environment through landfills. NS Power through our contracted service provider Efficiency One has collected 2.3 kg in 2015 and 19.2 kg in 2016 of mercury credits as a result of this program that can be used to compensate for the deferred mercury emissions. NS Power continues to offer the program in 2017.

[25] http://novascotia.ca/just/regulations/regs/envairqt.htm

8.0 RESOURCE ADEQUACY

8.1 Operating Reserve Criteria

Operating Reserves are generating 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 UARB. 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.[26]

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO),*[27] 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.

[26] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[27] New Brunswick's new 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[28] 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 versus exported to other areas.

NS Power performs an assessment of operational resource adequacy covering an 18-month period twice a year (in April and October proceeding the summer and winter peak capacity periods). These reports of system capacity and adequacy are posted on the NS Power OASIS site in the Forecast and Assessments Section.

8.2 Planning Reserve Criteria

8.2.1 Updated Planning Reserve Margin Loss of Load Expectation Study

Planning Reserve intends to maintain sufficient resources to serve firm customers. Unit forced outages, higher than forecasted demand, and lower than forecasted wind generation are all conditions that could individually or collectively contribute to a shortfall of dispatchable capacity resources to meet customer demand.

[28] The change in the capacity rating of Point Aconi, described in Section 4.1.1, will change the spinning reserve to 32 MW. The System Operator is currently reviewing and updating the appropriate procedures to reflect this change.

NS Power is required to comply with the NPCC reliability criteria that have been approved by the UARB. These criteria are outlined in *NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[29] and states that:

> 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.

The 2014 IRP Loss of Load Expectation (LOLE) study confirmed that the 20 percent planning reserve margin applied by NS Power is required to meet the NPCC reliability criteria. As parts of NS Power's steam fleet continue to be transitioned from base loaded to increasingly flexible operation, there may be upward pressure on forced outage rates associated with these units. Increased demands of wind-following on previously base-loaded steam generating units, coupled with high levels of intermittent variable generation on the system, may drive the need to increase the planning reserve margin in order to maintain NPCC reliability criteria. There is a strong correlation between the fleet forced outage rate and the resulting required planning reserve margin.

The results of any updated Planning Reserve Margin LOLE studies will be reported by NS Power in future 10 Year System Outlook Reports as more operating data related to renewables transition becomes available.

[29] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

8.3 Analysis of Currently Planned Levels of Variable Generation

NS Power continues to evaluate the coincidence of wind generation with peak load on an annual basis to better understand the Effective Load Carrying Capability (ELCC) or capacity value of wind assets on the NS Power system by completing studies using available data and both the LOLE and Cumulative Frequency Analysis (CFA) methodologies.

The LOLE methodology is a long standing utility industry standard for planning reserve margin assessment, which can be adapted to assess the capacity value of wind. This calculation is completed using the Probabilistic Assessment of System Adequacy (PASA) module of Plexos, and takes into account hourly actual wind, hourly actual load, generator capacities, and forced outage rates. The advantages of this methodology are that the calculation practices are well-established and the computation considers not just the coincidence of peak load and wind generation, but also the impact of the amount of wind generation proportional to the system (exhibiting declining capacity factor with higher penetration levels of wind). The main disadvantage of the LOLE approach is that the results can vary significantly year over year. As discussed in the 2016 10 Year System Outlook, the International Energy Agency (IEA) Wind Task 25 Final Report[30] recommends that between 10 and 30 years of wind and load data is required to establish a reliable ELCC of wind generation using LOLE calculations.

NS Power's Cumulative Frequency Analysis assessment of the ELCC of wind generation provides a second method of quantifying the capacity value of wind on the NS Power system. This technique analyzes a set of historical data points, in this case hourly wind generation and load, to determine how often a particular value is exceeded (e.g. wind correlation to peak). The objective of the analysis is to determine what minimum capacity factor of wind we can predict to be available to the NS Power system in peak hours, with corresponding certainty. Other jurisdictions including CAISO (California

[30] IEA Wind Task 25 Final Report - http://www.ieawind.org/AnnexXXV/PDF/Final%20Report%20Task%2025%202008/T2493.pdf

Independent System Operator), BPA (Bonneville Power Administration), and SPP (South West Power Pool) use variations of this approach. The CFA is completed using Excel and Oracle's Crystal Ball software, and takes into account hourly actual wind and hourly actual load, in the top 10 percent of peak demand periods. The advantage of this method is that the analysis is conducted on a top percentile of peak hours, focusing results on key hours for reliability. The disadvantages of the method are that it does not consider the proportion of wind relative to the system, and adjacent peaks can produce skewed results in either direction.

Until NS Power gains multi-year operating experience with approximately 600 MW of wind generation, in order to acquire sufficient data to reliably estimate the ELCC of wind generation in Nova Scotia, there could be a risk to system reliability if the capacity value of wind generation is overstated. This is particularly true given the relatively large installed wind capacity on the NS Power system.

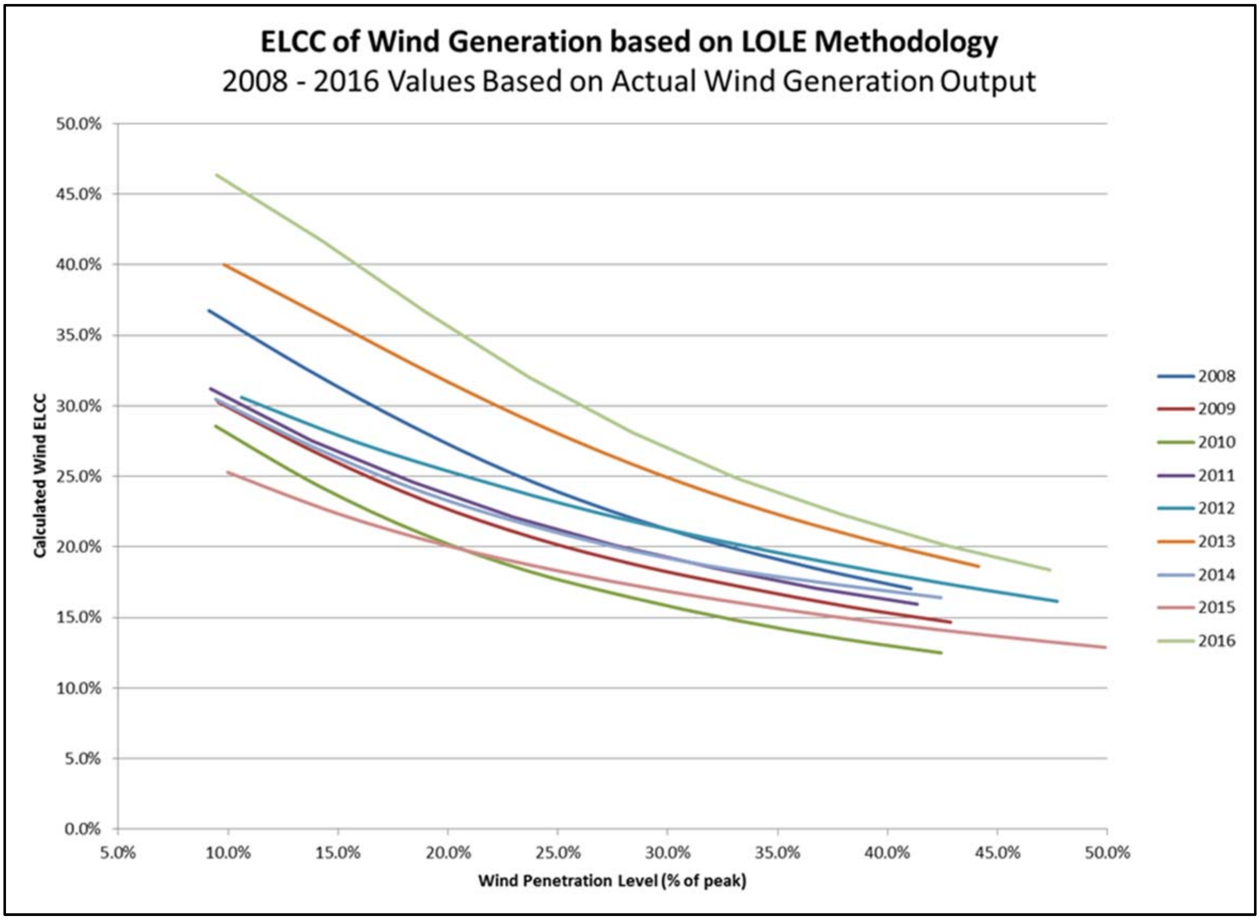
Figure 22 provides the updated results of the LOLE study for the years 2008 – 2016 to determine the capacity value of currently planned wind. The ELCC of wind generation based on this multi-year LOLE methodology can vary from 15 to 28 percent depending on the study year, at the presently contracted level of in-province wind generation of approximately 600 MW. **Figure 23** provides the updated Cumulative Frequency Methodology study results, which estimate the capacity value of wind at approximately 8 percent, at a 90 percent confidence level. Loss of Load Expectation is a robust methodology for calculating wind capacity value; however, as 10 to 30 years of data is recommended for accuracy, the Cumulative Frequency Analysis provides important validation of LOLE results with a focus on reliability. As noted above, further wind generation data at the 600 MW level will need to be studied to produce a more reliable estimate of wind generation capacity value. Incremental wind above the currently planned levels will have a declining capacity value on the system, as illustrated by the declining curves in **Figure 22**. The Company understands this may be explored in the ongoing UARB Generation Utilization & Optimization process being initiated by the Board.

Some municipal load is served from one independent wind farm supply. This generation is not included in NS Power's sourced wind generation but contributes to operational considerations of the total amount of wind generation.

8.3.1 Wind Capacity Value Study: Loss of Load Expectation Results

Figure 22 provides a chart of the ELCC of wind calculated using LOLE methodology.

Figure 22: ELCC of Wind Generation using LOLE Methodology



8.3.2 Wind Capacity Value Study: Cumulative Frequency Analysis Results

Load and wind data was provided as input to the model, and a continuous Beta probability distribution was fit to the data. This statistical distribution was then used to calculate the cumulative probability at various confidence levels. The results of Cumulative Frequency analysis, based on eight years of actual wind generation data, are presented in **Figure 23.**

Figure 23: ELCC of Wind Generation using Cumulative Frequency Methodology

Confidence Level	Capacity Value of Wind
95%	4%
90%	8%
85%	12%
80%	16%

For the Resource Adequacy Assessment in Section 8 of this report, NS Power continued to use a wind capacity value of 17 percent for NRIS and 0 percent for ERIS resources (averaging to 12 percent overall ELCC of Nova Scotia wind generation resources).

NS Power will continue to monitor the system as the additional planned variable COMFIT generation comes online and more experience is gained with an elevated wind penetration. The Company will report on the need for any flexible resources in future 10 Year System Outlook Reports.

NS Power continues to evaluate operations with increased levels of renewable resources through ongoing system studies and analysis. NS Power is enhancing operational guidelines to deal with increased levels of wind generation, particularly during light load conditions. Various aspects of wind generation operation are being investigated to understand the potential reliability impacts of wind generation including effects on system inertia, frequency response, and voltage support.

8.4 Energy Resource Interconnection Service Connected Resources

In its letter to NS Power dated February 9, 2016 regarding the 2016 10 Year System Outlook Report, the UARB noted with respect to capacity contribution of ERIS wind resources:

> …during the IRP process, NSPI committed to determining the extent to which ERIS connected wind resources could be counted toward resource adequacy during the winter peak period. In its response to IR-10, NSPI stated that the System Operator was asked to study the Nuttby wind project and that the outcome of that study will inform the necessity of similar studies for other ERIS wind projects. However, no information was provided on the timing of that study or if any outcomes had already been known. Furthermore, although NSPI stated that sections of the Generator Interconnection Procedures require a System Impact Study on each facility, no indication was given on the timing or how that process could be expedited or amended for existing wind generation facilities. The objective is not necessarily to determine how a facility can be reclassified from ERIS to NRIS, but to determine how much of its capacity could be counted as a contribution during the winter peak period.
>
> The Board notes from NSPI's response to IR-10, that significant capacity contributions (not zero) were being made by ERIS projects during the winter peak hours over the past five years. This observation needs to be given further consideration in order to facilitate proper accounting of wind capacity in meeting resource adequacy needs. In addition, the Board notes from NSPI's recent COMFIT report, that the average annual capacity factor was 40% for large wind projects and 26% for small wind projects.
>
> The Board is of the view that further assessment of the methods to address this question, combined with a review of NSPI's actual operating experience with wind resources to date, would be helpful in determining whether the IRP assumptions continue to be appropriate.

NS Power notes that information on the Generator Interconnection Procedures (GIP) required to transition the aforementioned wind resources from ERIS to NRIS was provided by the Company to participants in the Tufts Cove Technical Conference held by NS Power on April 13, 2017. A copy of the presentation is attached as **Appendix A**.

In 2016, due in part to uncertainty around equivalency agreements and Federal requirements concerning retirements of coal plants, work on the Nuttby Wind Farm ERIS – NRIS transition was postponed while a broader strategy was devised. An internal study containing all ERIS facilities has now re-commenced. This study is not associated with the Generator Interconnection Procedures and as such does not require the involvement of each ERIS facility owner. The results will provide an overview of the effort and costs required to transition these projects to NRIS and the potential partial capacity contribution level based on current system configuration and conditions. The study results will be impacted by any new committed generation projects that proceed to at least the System Impact Study under the GIP. The new study is expected to be complete by the end of Q3 2017.

8.5 Load and Resources Review

The ten year Load and Resources Outlook in **Figure 24** and **Figure 25** below are based on the capacity changes and DSM forecast in **Figure 6** above, and provides details regarding NS Power’s required minimum forecasted planning reserve margin equal to 20 percent of the firm peak load.

The current forecast indicates a small capacity deficit may exist by 2023. NS Power will continue to monitor potential deficits or apparent surpluses as forecasts continue to evolve and will adjust decisions accordingly. NS Power’s approach to unit utilization and preserving operational flexibility allows for the delay of these types of forecast-sensitive decisions.

Figure 24: NS Power 10 Year Load and Resources Outlook

Load and Resources Outlook for NSPI - Winter 2017/2018 to 2026/2027
(All values in MW except as noted)

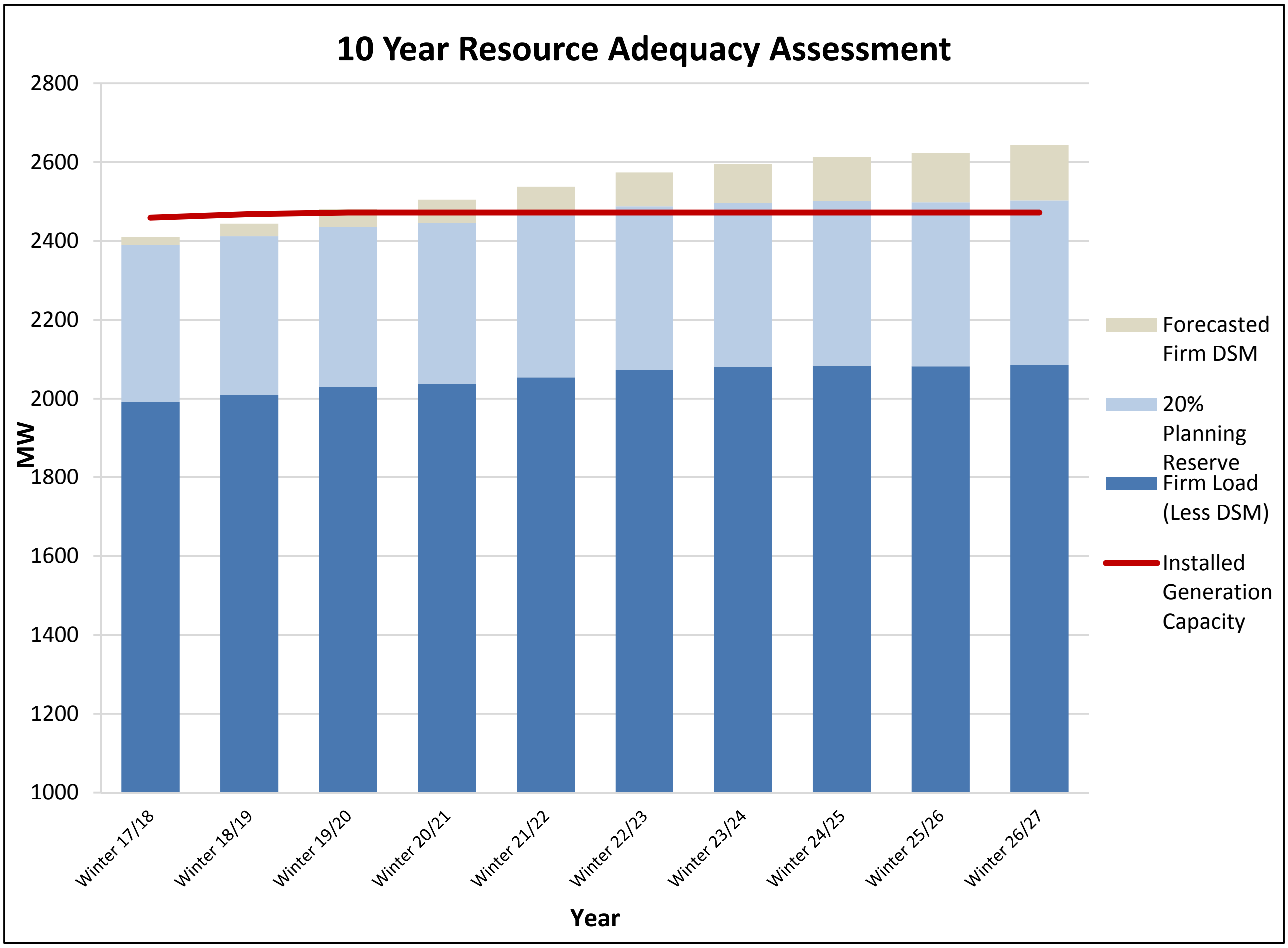
		2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027
A	Firm Peak Load Forecast	2,013	2,043	2,075	2,097	2,126	2,158	2,178	2,196	2,209	2,227
B	DSM Firm[1]	20	32	46	59	73	86	99	112	126	141
C	Firm Peak Less DSM (A - B)	1,993	2,010	2,029	2,038	2,054	2,073	2,080	2,084	2,082	2,086
D	Required Reserve (C x 20%)	399	402	406	408	411	415	416	417	416	417
E	Required Capacity (C + D)	2,391	2,412	2,435	2,445	2,464	2,487	2,496	2,501	2,499	2,503
F	Existing Resources	2375	2375	2375	2375	2375	2375	2375	2375	2375	2375
	Firm Resource Additions:										
G	Thermal Additions[2]	33			-153						
H	Biomass[3]	43									
I	Community Feed-in-Tariff[4]	8	9	3							
J	Tidal Feed-in-Tariff [5]	0.4	0.5	1							
K	Maritime Link Import				153						
L	Total Annual Firm Additions (G + H + I + J + K)	84	9	4	0	0	0	0	0	0	0
M	Total Cumulative Firm Additions (L + M of the previous year)	84	94	97	97	97	97	97	97	97	97
N	Total Firm Capacity (F + M)	2459	2468	2472	2472	2472	2472	2472	2472	2472	2472
	+ Surplus / - Deficit (N - E)	67	56	37	27	8	-15	-24	-29	-27	-31
	Reserve Margin % [(N - C)/C]	23%	23%	22%	21%	20%	19%	19%	19%	19%	19%

NOTES:

1. Cumulative estimated Firm Peak reduction based on DSM forecast.
2. Thermal includes Burnside #4 (winter capacity 33 MW) which is assumed to be returned to service in 2017/2018. Also includes assumed Lingan 2 retirement when firm capacity is provided from the Maritime Link.
3. 43 MW from the PH Biomass plant which will be able to provide firm service following the transmission upgrades required for the Maritime Link.
4. The Community Feed-in-Tariff represents distribution-connected renewable energy projects, totalling 176.7 MW installed by beginning of 2020 (156.6 wind, 20.1 MW non-wind).
5. Tidal Feed-in-Tariff - Tidal projects assume 12.5 MW by 2020.

Figure 25 is a graphical representation of the assessment completed in **Figure 24** above. It provides a breakdown of the forecasted system demand and planning reserve margin and how this will be served by the system capacity. A small capacity shortfall shows starting in 2023. As discussed above, NS Power will continue to evolve its use of the end-use load forecasting methodology as its understanding of the approach matures.

Figure 25: Firm Capacity and Peak Demand Analysis

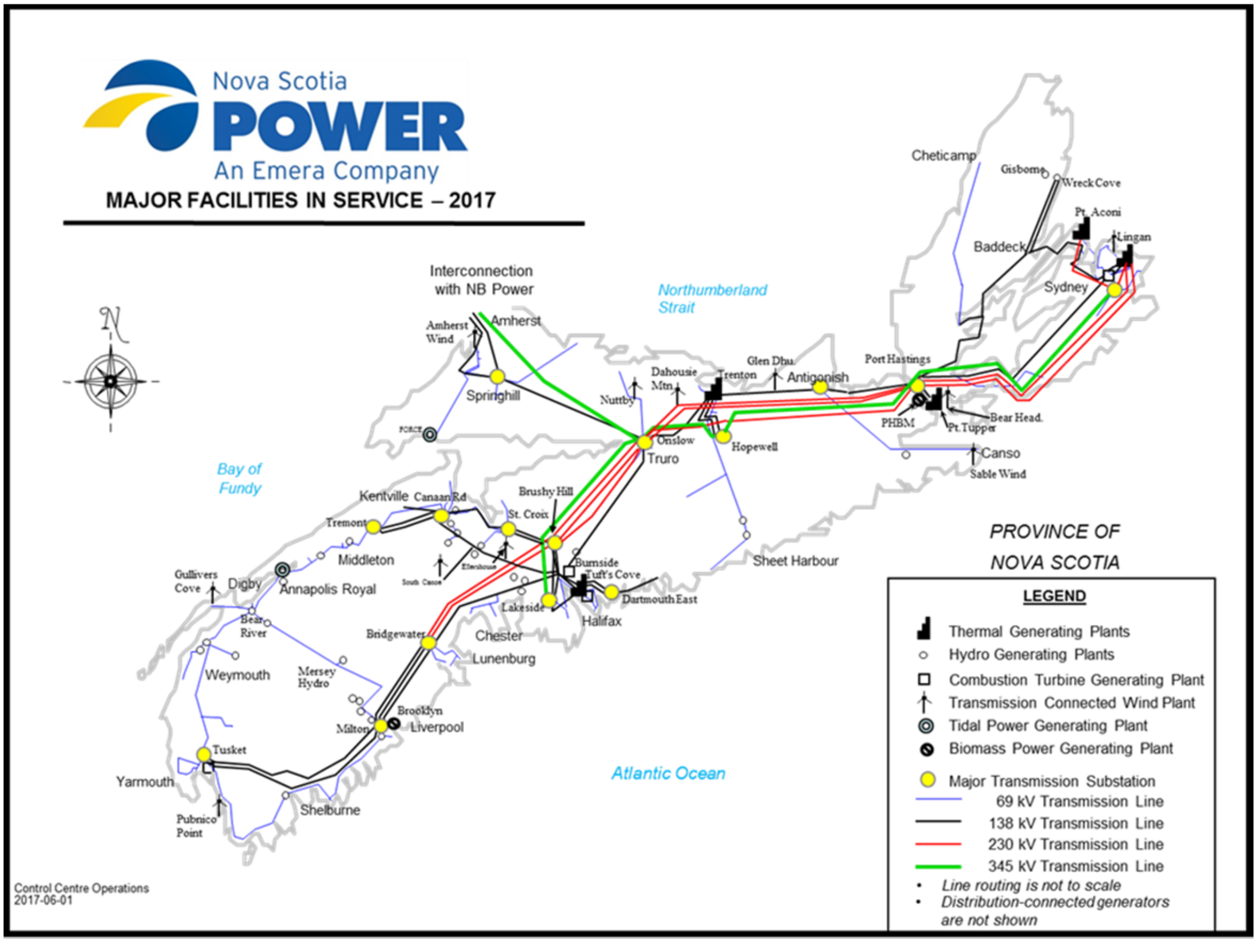


9.0 TRANSMISSION PLANNING

9.1 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 26**.

Figure 26: **NS Power Major Facilities in Service 2017**



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

The 230 kV transmission system is approximately 1271 km in length and is comprised of 47 km of steel/laminated structures and 1224 km of wood pole lines.

The 138 kV transmission system is approximately 1871 km in length and is comprised of 303 km of steel structures and 1568 km of wood pole lines.

The 69 kV transmission system is approximately 1560 km in length and is comprised of 12 km of steel/concrete structures and 1548 km of wood pole lines.

Nova Scotia is synchronously interconnected with the New Brunswick electric system through one 345 kV and two 138 kV lines providing up to 350 MW of transfer capability to New Brunswick and up to 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. In 2017, Nova Scotia will be asynchronously interconnected with the electric power system of the island of Newfoundland via the 500 MW high-voltage direct current (HVdc) Maritime Link. In 2018, the island of Newfoundland will be asynchronously connected to Labrador via the HVdc Labrador Island Link, which will be connected to the Quebec electric system via Churchill Falls.

9.2 Transmission Design Criteria

NS Power, consistent with good utility practice, 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.

9.2.1 Bulk Power System

The NS Power Bulk Power System (BPS) 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. As a result, those portions of NS Power's transmission network wherein 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 BPS elements.

9.2.2 Bulk Electric System

On July 1, 2014, the NERC Bulk Electricity System (BES) definition took effect in the United States. The 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 the UARB has approved an NS Exception Procedure[31] for elements of the transmission system that are operated at 100 kV or higher for which contingency testing has demonstrated no significant adverse impacts outside of 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.

[31] M06930, NERC BES Definition Project Application, UARB Order 2017 NSUARB 51, April 6, 2017.

In its Order approving the NS Exception Procedure, the Board provided:

> IT IS ORDERED that the NERC BES definition (Appendix A to the Application), the NSPI BES Exception Procedure and BES Exception Request Form attached hereto as Appendix "A", and the BES Exception Requests listed in Appendix "B" attached hereto are hereby approved, all effective as of the date of this Order;
>
> IT IS FURTHER ORDERED that NSPI's plan to address compliance gaps as described in the Application is approved and compliance work for newly identified BES elements shall be completed within five years from the date of this Order. The Board directs NSPI to include a report on the status of compliance gaps in its annual 10 Year System Outlook Report.[32]

The following gaps have been identified with respect to the implementation of the BES definition in NS Power, and the Company will complete this work within five years from the Board's Order dated April 6, 2017:

- The SVC at the 120H Brushy Hill substation has been classified as a BES element. A project is underway to refurbish this SVC and this capital item includes equipment that will meet the BES disturbance monitoring requirements on the SVC.

- The 85S Wreck Cove substation is not classed as BES but the generator transformers and the generators are classed as BES. An assessment will be scheduled in 2017 to determine sequence of events recorder capabilities of the generator transformer and generator protection devices.

- The 14H – Burnside and 83S – Victoria Junction generators have been classified as BES elements. An assessment will be scheduled in 2017 to determine sequence of events recorder capabilities of the generator transformer and generator protection devices.

[32] Ibid, page 3.

- At 79N Onslow and 103H Lakeside there are deficiencies in the monitoring capabilities for the shunt devices, and modifications are required to bring these substations into compliance. An assessment of these deficiencies and associated remedial actions will be scheduled in 2017.

- The 101S Woodbine substation has a project underway to expand the substation and this project includes equipment that will meet BES disturbance monitoring requirements.

9.2.3 Special Protection Systems

NS Power makes use of Special Protection Systems (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 or shedding load. The NS Power system has several transmission corridors that are regularly operated at limits without incident due to these SPS.

9.2.4 NPCC A-10 Standard Update

An A-10 Working Group under the NPCC Task Force on Coordination of Planning (TFCP) has been created to conduct a review of the NPCC Document A-10: Classification of Bulk Power System Elements, and its application. Membership was solicited from the NPCC Task Forces on Coordination of Planning, Coordination of Operation, System Protection and System Studies, and other interested representatives of NPCC Member Companies.

At present, Document A-10 provides a methodology to identify BPS elements in the interconnected NPCC Region, and all NPCC criteria apply to these BPS facilities. However, there are questions as to whether the A-10 methodology produces the appropriate level of reliability in NPCC.

The objectives of the review are as follows:

(1) Consider existing and alternative methodologies to:

- Identify critical facilities for the applicability of NPCC Directories;
- Simplify the existing methodology to make it less labor-intensive;
- Improve consistency across Areas in application and outcomes of the methodology.

(2) Consider conforming changes to NPCC documents to implement any necessary improvements as a result of the review.

NS Power has representation on the A-10 Working Group that is performing the review for TFCP. To date, existing A-10 methodologies have been examined for each NPCC area. At this time, the A-10 Working Group anticipates the review will take two years, and expects to investigate updates to the A-10 methodology in addition to potential new methodologies. Testing of new methodologies is also included in this timeframe.

NS Power will contribute to the A-10 Working Group, with a goal of ensuring that any changes to the existing A-10 methodology will result in solutions that offer the best value for NS Power customers while meeting NPCC's stated objectives. Changes to the A-10 methodology may result in the identification of new BPS elements on NS Power's transmission system.

9.3 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 (for example, conductor, 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 required 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 or if line uprating is required.

9.4 Transmission Project Approval

The transmission plan presented in Section 11.1 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 identified 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 UARB. 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 UARB.

In 2008, the Maine and Atlantic Technical Planning Committee (MATPC) was established to review intra-area plans for regional resource integration and transmission reliability. The MATPC forms the core resource for coordinating input to studies conducted by each member organization and presenting study results, such as evaluation of transmission congestion levels in regards to the total transfer capabilities on the utility interfaces. This information is used as part of assessments of potential upgrades or expansions of the interties. The MATPC has transmission planning representation from NS Power, Maritime Electric Company Ltd., Emera Newfoundland and Labrador, Northern Maine Independent System Administrator (which includes Emera Maine Northern Operating Region and Eastern Maine Electric Cooperative), Newfoundland and Labrador Hydro, and NB Power. NS Power and NB Power jointly conduct annual Area Transmission Reviews for NPCC.

10.0 REGIONAL DEVELOPMENT

10.1 Maritime Link

The Maritime Link is a bipolar connection between 101S-Woodbine and Bottom Brook terminal station (BBK) in Newfoundland that is based on Voltage-Source Converter (VSC) technology. Each pole is configured as an asymmetric monopole VSC rated for 200kV and 250MW on the DC side of the converter. The bipole configuration allows for redundancy of half of the total rated transfer capability.

The Maritime link is a combination of cable and overhead line: approximately 171 km of subsea cable and 142 and 46 km of overhead line on the NL and NS sides respectively. The AC yard for each pole at each converter station has a converter transformer with high-side tap changer and a pre-insertion resistor, along with filtering, protection, and measuring apparatus. The DC side has a smoothing filter, DC line disconnector, and high speed switch for fast discharge of the DC line. The active and reactive power levels can be constant, gently ramped, or nearly instantly changed (e.g. during use within a Special Protection System).

10.2 Nova Scotia – New Brunswick Intertie Overview

The power systems of Nova Scotia and New Brunswick are interconnected via three overhead transmission lines; one 345 kV line from Onslow, Nova Scotia to Memramcook, New Brunswick, and two 138 kV lines from Springhill, Nova Scotia to Memramcook, New Brunswick. Since there is only a single 138 kV line between Springhill and Onslow in Nova Scotia, the intertie can be considered to be comprised of a single 345 kV circuit in parallel with a single 138 kV circuit. The primary function of the intertie is to support system reliability.

Access to the Nova Scotia - New Brunswick intertie is controlled by the terms of the respective OATTs of NS Power and NB Power. As shown in **Figure 15** there is currently one active Transmission Service request for Point-to-Point Transmission Service across the NB-NS intertie.

Power systems are designed to accommodate a single contingency loss (i.e. loss of any single element and certain multiple elements) and since the 345 kV line carries the majority of the power flow (between NS and NB), loss of a 345 kV line becomes the limiting factor. Power flow on the 138 kV lines is also influenced by the loads in Prince Edward Island and Sackville, New Brunswick, as well as Amherst, Springhill and Debert, Nova Scotia. Wind and planned tidal generation in the Amherst/Parrsboro area can also impact 138 kV line loading.

Import and export limits (both firm and non-firm) on the intertie have been established to allow the Nova Scotia and the New Brunswick system to withstand a single contingency loss. The limits are currently set at up to 350 MW export and up to 300 MW import. These figures represent limits under pre-defined system conditions, and differ for Firm versus Non-Firm Transmission Service. Conditions which determine the actual limit of the interconnection are shown in **Figure 27.**

Figure 27: **Conditions Determining Limits**

Export	Import
Amount of generation in Nova Scotia that can be rejected or run-back via SPS action	Nova Scotia system load level (Import must be less than 22% of total system load)
Reactive Power Support level in the Metro Area	Percentage of synchronous generation in Nova Scotia (providing inertia and frequency response)
Arming status of SPS New Brunswick	New Brunswick export level to Prince Edward Island and/or New England
Real time line ratings (climatological conditions in northern Nova Scotia)	Seasonal line ratings (climatological conditions in northern Nova Scotia)
Net Northern Nova Scotia System load level	Load level in Moncton area plus flow to Prince Edward Island
Largest single loss of load contingency in Nova Scotia	Largest generation/source contingency in Nova Scotia
Generation in the Amherst/Parrsboro area	Generation in Amherst/Parrsboro area
Internal transmission limitations in Nova Scotia (Cape Breton Export, Onslow Import)	Status of generation and transmission lines in New Brunswick
	Status of the intertie between New Brunswick and Quebec
	Conditions on intertie between New Brunswick and New England

If the 345 kV Nova Scotia - New Brunswick intertie trips while exporting, the parallel 138 kV lines can be severely overloaded and potentially trip, causing Nova Scotia to separate from New Brunswick. If this happens, the Nova Scotia system frequency (measured in Hertz) will rise, risking unstable generation plant operation and possible equipment damage. To address this, NS Power uses a fast-acting SPS to reject or run back sufficient generation to prevent separation.

If the NS Power system becomes separated from the North American interconnected power system during heavy import, Nova Scotia system frequency will drop. Depending on the system configuration at the time of separation and the magnitude of the import electricity flow that was interrupted, the system will respond and re-balance. The system does this by automatically rejecting firm and non-firm load through under-frequency load shedding (UFLS) protection systems as required by NPCC Standard PRC-006-NPCC-1 Automatic Under-frequency Load Shedding.

The degree of load shedding will be impacted by the amount of in-province generation supplied by non-synchronous power sources, such as wind energy conversion systems, photovoltaic (solar), or tidal power due to the technical characteristics of those sources. High penetration levels of non-synchronous generation in Nova Scotia reduce the total inertia of the NS Power system, thereby increasing the rate at which the Nova Scotia system frequency declines, resulting in the potential for higher levels of load shedding through UFLS. NS Power has recently begun discussions with wind turbine manufacturers to determine the technical capability of existing and new generation to provide ancillary services currently only available through conventional hydro and thermal generation, such as tie-line control (AGC), operating reserve, and synthesized inertia.

The loss of the 345 kV line between Onslow, Nova Scotia and Memramcook, New Brunswick is not the only contingency that can result in Nova Scotia becoming separated from the New Brunswick Power (NB Power) system while importing power. All power imported to Nova Scotia flows through the Moncton/Salisbury area of New Brunswick. Since there is no generation in the Moncton/Salisbury area, and only a limited amount of generation in Prince Edward Island (PEI), power flowing into Nova Scotia is added and shares transmission capacity with the entire load of Moncton, Memramcook, and PEI. In 2016, firm transmission capacity from NB to PEI was increased to 300MW.

NB Power restricts power export to Nova Scotia to a level such that any single contingency would not cause adverse impacts on New Brunswick, PEI, or the intertie with New England. Any transmission reinforcement proposed to improve reliability, increase import and export power capacity or prevent the activation of UFLS in Nova Scotia must also consider the reinforcement of the southeast area of the New Brunswick transmission system.

Although joint studies have been conducted, at this time the timing and configuration of an expansion to the provincial intertie has yet to be determined. The transmission projects associated with the Maritime Link will reinforce the 138 kV portion of the intertie and will significantly increase the firm export capability from Nova Scotia. When this new circuit is constructed between Onslow and Springhill, it will reduce the exposure to UFLS, potentially increase import capacity under certain seasonal loading conditions, and improve transmission capacity for generation projects in the Amherst/Parrsboro/Springhill area. However, import capacity will still be limited by transmission congestion in southeast New Brunswick.

Given the dynamic nature of the provincial and regional electricity markets it is likely that further upgrades may be required over the next decade. Over the past several years, NS Power has secured easements to prepare for the eventuality of expanding the intertie with a second 345kV line between Onslow and New Brunswick. Any remaining easements will be sought once a determination is made to proceed with construction of the second intertie.

The Maritime Link could provide some support during incidents involving isolation from NB Power; however, this support would depend on the operating mode of the link and the status of the Newfoundland and Labrador power system at the time. The NPCC reliability criteria require systems to survive loss of an entire HVdc terminal, which could approach 500 MW if the Maritime Link is operating at full capacity. Loss of this source could result in unacceptable voltage conditions on the NB Power system if NS Power is importing power from NB simultaneous with imports via the Maritime Link. Therefore, it will be necessary to impose coincident import limits.

10.3 Co-operative Dispatch

In 2016, NS Power and NB Power extended, and continued to operate under, a Joint Dispatch Pilot Agreement in order to create efficiencies in the generation dispatch and lower fuel costs for customers of the two utilities. On December 20, 2016, the Parties executed a new Cooperative Dispatch Agreement (CDA) which formally moved the initiative from a pilot phase to an ongoing operational phase. The CDA came into effect on January 1, 2017 and will automatically renew annually unless terminated by either party. In 2016, the total shared savings created through this initiative were $2.1 million. NS Power and NB Power continue to meet regularly to discuss opportunities for generating additional savings.

10.4 Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI)

In December of 2016, NS Power issued a Request for Proposals for completion of an Atlantic RECSI Study on *Assessment of Electricity Infrastructure Projects with Potential to Reduce GHGs*. The objective of the study, which will be undertaken on behalf of the four Atlantic Provinces and the Government of Canada, is to “gain regional consensus on the most promising electricity infrastructure projects in the Atlantic Provinces that support the transition to lower GHG emissions and the replacement of coal-fired generating capacity with an expected load increase due the electrification of buildings and transportation for the years 2030 and 2041.” The study contract was awarded in February 2017 and was initiated in March. The RECSI study is scheduled to be completed by January 31, 2018.

11.0 TRANSMISSION DEVELOPMENT 2017 TO 2026

11.1 Transmission Development Plans

Transmission development plans are summarized below. As highlighted earlier, these projects are subject to change. For 2017, the majority of the projects listed are included in the 2017 Annual Capital Expenditure Plan.

2017

- 120H Brushy Hill SVC controls replacement project was completed in May 2017. (CI 46339).

- Two new 50 Mvar capacitor banks installed in Halifax Regional Municipality in 2017. These will provide increased Onslow South transfer capability at system load levels above 1500 MW. (CI 46587).

- New 138 - 12 kV distribution substation at Prime Brook, Sydney. Transformer, rated at 15 MVA, will be tapped off transmission line L-6539. (CI 45306) L-6537 transmission line upgrade to replace deteriorating assets and address ground clearance. (CI 47914).

- A second 138 kV - 25 kV transformer is being installed at 2H Armdale to reduce the exposure to extended outages in the Peninsula core. (CI 46811).

- Separating L-8004 and L-7005 at the Canso Causeway crossing to increase the Cape Breton export limit. This upgrade is associated with the Maritime Link project. (CI 43678).

- Terminate transmission lines L-7011 and L-7012 at the 101S Woodbine substation. This upgrade is associated with the Maritime Link project and will be funded by NSP Maritime Link.

- Woodbine substation expansion to accommodate new 345/230 kV transformer and breakers associated with transmission line terminals and HVDC converter station. This upgrade is associated with the Maritime Link project and will be funded by NSP Maritime Link.

- At Port Hastings, the 69 kV bus, 2C-T1, and 2C-T2 will be removed and a new 138-25 kV transformer will be installed. (CI 44981).

- Retirement and removal of L-5503 between Port Hastings and Cleveland. Ground clearance issues with the 230 kV circuit L-7003 between Port Hastings and Onslow will be addressed. Upgrades began in 2015 and are expected to be completed by 2017. (CI 44987).

2018

- Addition of Spider Lake substation in the Dartmouth area to reduce the need for out of economic merit operation of Tufts Cove generation due to local transmission constraints. (CI 48022).

- 2C Port Hastings 138kV substation will be uprated to meet NPCC BPS standards.

- L-6513 transmission line re-build to increase the line rating. This upgrade is associated with the Maritime Link project. (CI 43324).

- In accordance with a directive from NPCC, Bulk Power System elements which previously fell within the “grandfather clause” of NPCC Directory 04 System Protection Criteria must have duplicate high-speed protection systems and duplicate station batteries. Lingan 230 kV will be uprated in 2018. (CI 46757).

- Replacement of Lingan 230 kV Westinghouse Gas insulated Switchgear (GIS) equipment to mitigate the potential failure and increase reliability. (CI 46591).

- 88S Lingan 138kV will be uprated to meet NPCC BPS standards.

- Replacement of 73W-T1 transformer at Auburndale with a new 138/69-25 kV transformer rated at 15/20/25 MVA.

- Terrace Street 69 kV substation will be retired once the existing 4 kV distribution load is converted to 12 kV (the latter is scheduled for 2017).

- New Mount Hope 69kV-25kV padmount substation in Dartmouth.

12.0 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 in Nova Scotia continues to drive a transformation of the NS Power electric power system. Within the 10-year window considered in this Report, NS Power will experience further reductions in hard caps for CO_2, SO_2, NO_X and mercury, and will be required to serve 40 percent of sales with renewable electricity from qualifying sources. It remains uncertain what other environmental federal or provincial policy changes could come into effect within the 10-year period.

Compliance drives a shift towards renewable electricity generation and a reduction in conventional coal fired electricity production. The integration of variable renewable resources on the NS Power system has imposed revised operating and flexibility demands on previously base-loaded steam units, which continue to bring essential reliability services to the system. NS Power will participate in the Board's Generation Utilization and Optimization process, which is expected to advance understanding among the utility and stakeholders of this complex matter.

As discussed in the 2017 Load Forecast Report, NS Power continues to review and evolve the end-use forecasting methodology. The Company will continue to analyze and adjust its utilization and retirement strategy accordingly as this methodology matures.

Transmission of energy to be delivered over the Maritime Link, continued compliance with Reliability Standards, and opportunities for regional cooperation are key inputs to Transmission Planning in the ten-year window of this report.

Wind Capacity Contribution, including ERIS resources

Appendix B

1. Effective Load Carrying Capability Evaluations
   a) LOLE Methodology
   b) Cumulative Frequency Analysis

2. ERIS Capacity Contribution
   a) ERIS vs NRIS
   b) Generator Interconnection Procedures

Wind Capacity Value
Effective Load Carrying Capability of Wind

Capacity Value of Wind:

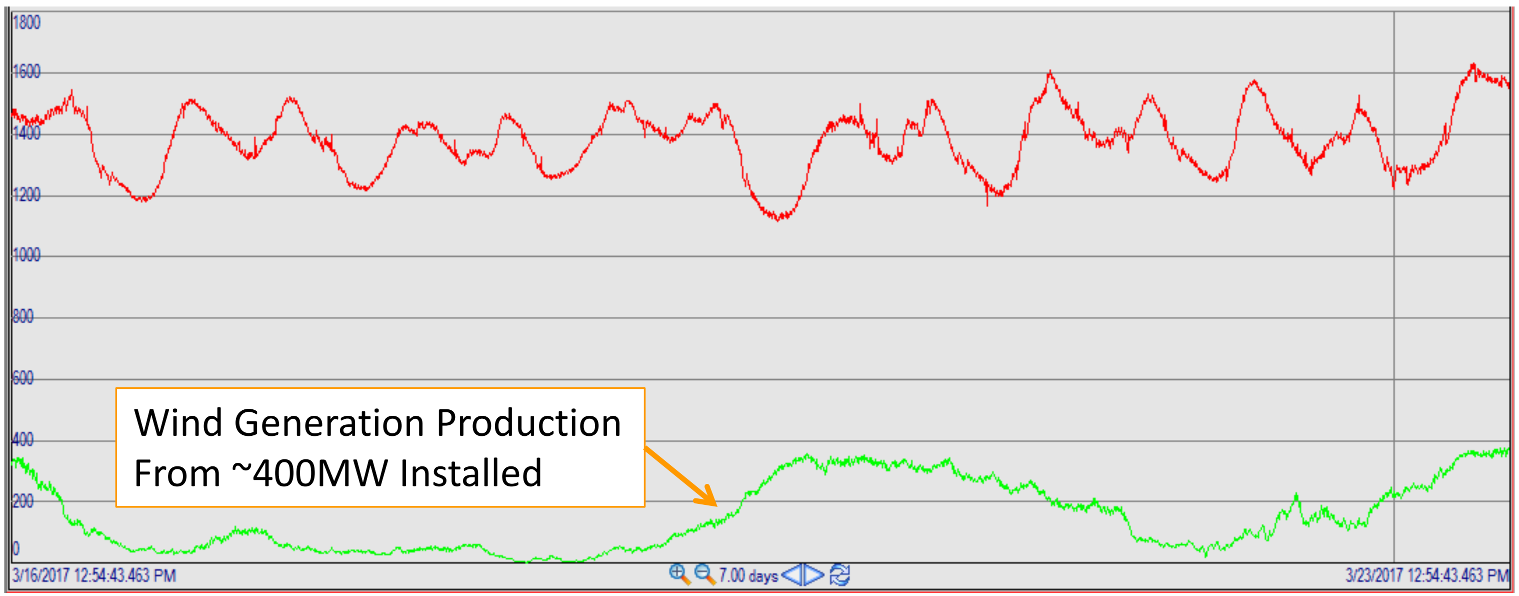
How much wind generation is expected to **consistently** be available **during peak demand.**

- Counted as firm capacity in system adequacy assessments and forecasts.
- If overstated, can lead to erosion of system reliability and inability to serve firm peak load.
- If understated, can lead to overbuilding capacity.

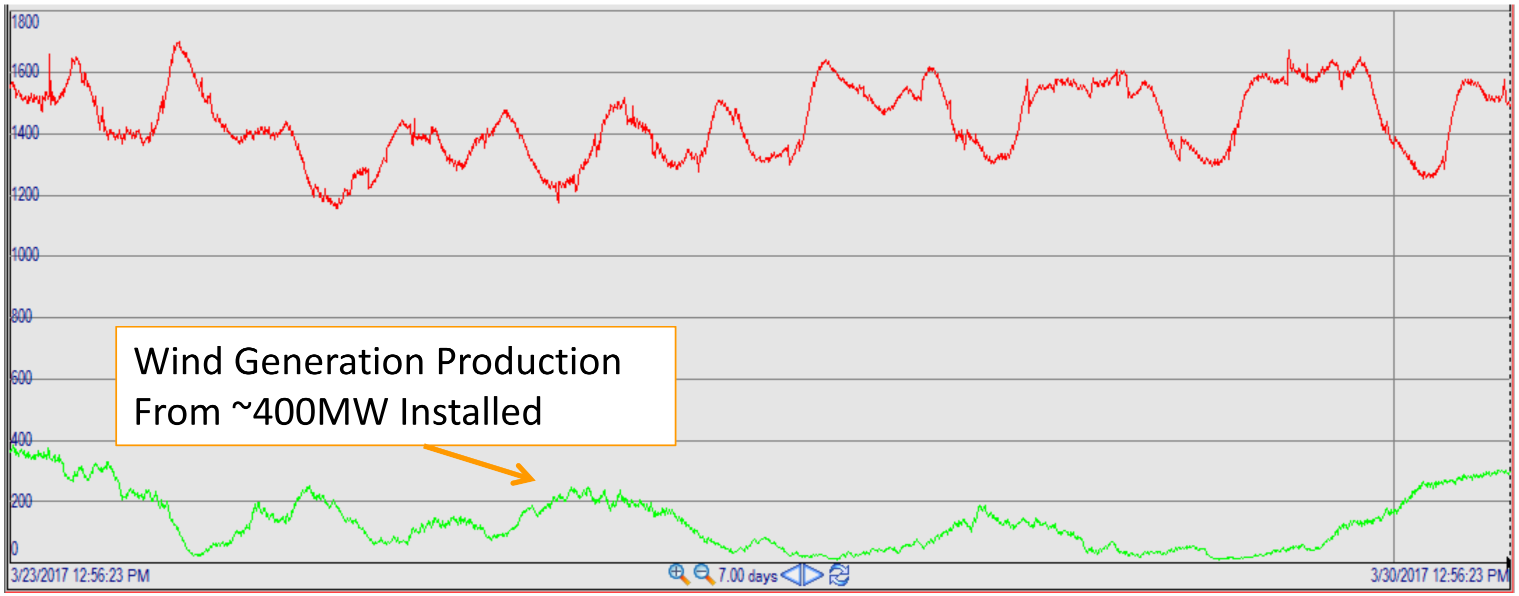
EXAMPLE:

- If capacity value of wind set at 50%, NSP could theoretically plan to operate system at all times with ~4,500 MW of wind and <u>no other generation</u>.
  - **<u>Not possible</u>, wind is variable down to 0**

Wind Production 2017/03/16-2017/03/23

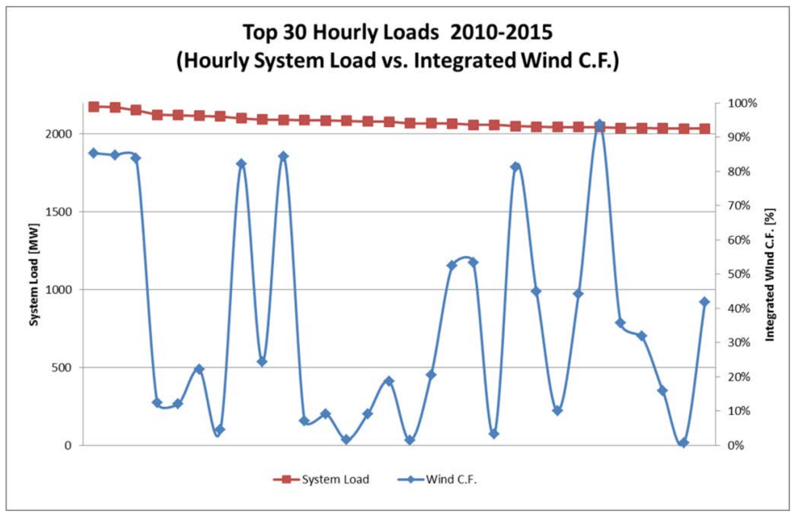


Wind Production 2017/03/23-2017/03/30



Wind Capacity Value System Implications

- Wind generation on the NS Power system is bi-modal:
  - There are peak demand hours when significant wind generation is present
  - There are peak demand hours when no wind generation is present



- At a 17% wind capacity value, during peak demand hours with no wind, **almost 30% of the planning reserve margin is at risk**.

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Wind Capacity Value
Effective Load Carrying Capability of Wind

Two methodologies commonly used in the industry to calculate wind capacity value:

- Loss of Load Expectation (LOLE)
- Cumulative Frequency Analysis

- NS Power uses both in an annual study as part of the 10 Year System Outlook.

Wind Capacity Value
Loss of Load Expectation (LOLE) Study

Overview:

- Long-time utility industry standard for planning reserve margin assessment
- Analyzes the effects of DAFOR on system reliability
  - Intermittent nature of wind similar for analysis

Advantages:

- Calculation practices well-established
- Computation considers not just coincidence of peak load and wind generation, but also impact of amount of wind generation proportional to system

Disadvantages:

- Results vary significantly year-to-year (IEA recommends 10 – 30 years of wind/load data to establish reliable ELCC)

Wind Capacity Value
Loss of Load Expectation (LOLE) Study

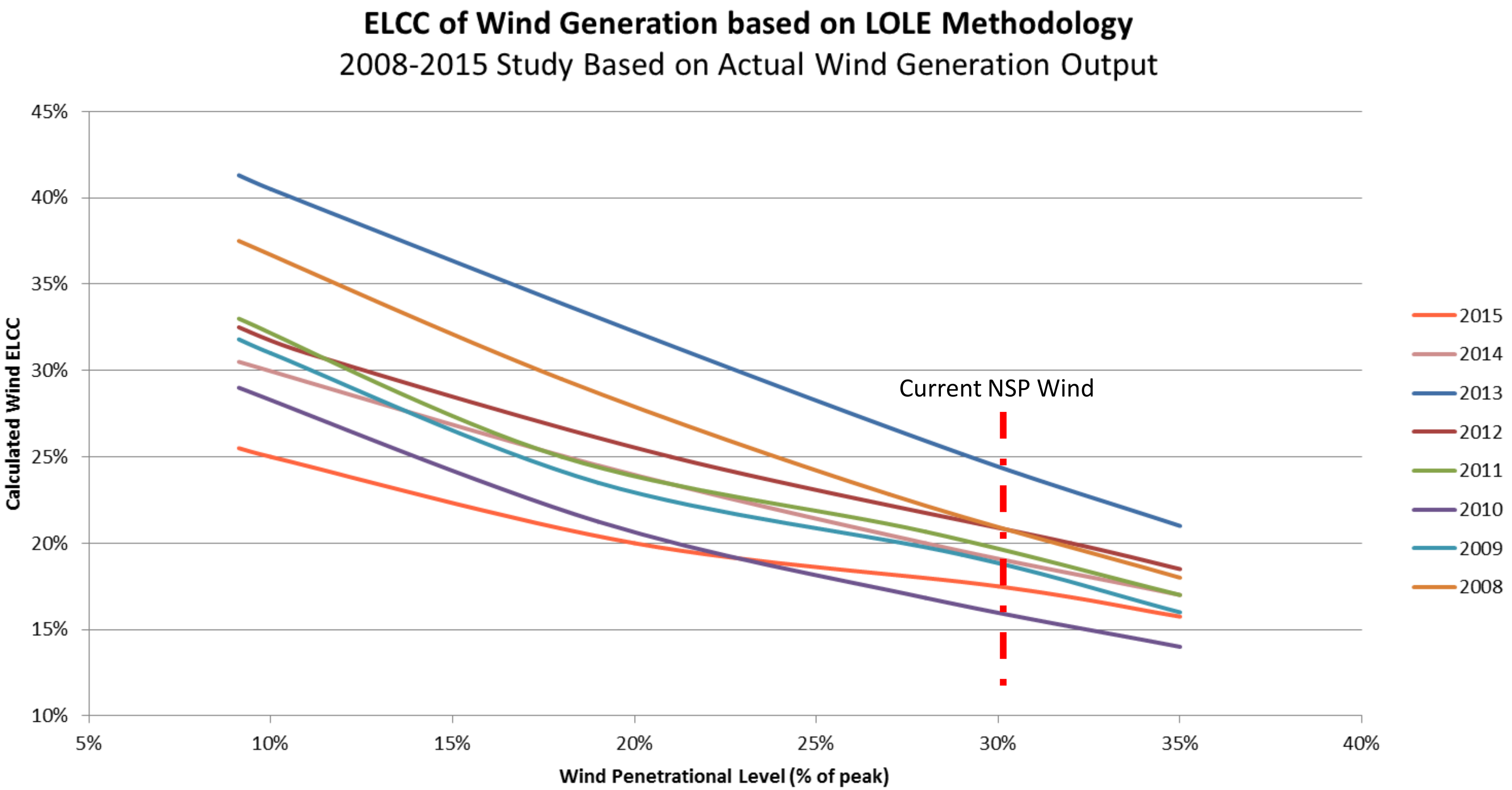
Methodology:

- Calculated using the Probabilistic Assessment of System Adequacy (PASA) module of PLEXOS Model
- Quantify the firm capacity provided by wind by:
  - Calculating LOLE of the NSP system including wind
  - Assessing the amount of firm generation required to produce an equivalent LOLE on the system without wind

Input Assumptions:

- Hourly actual wind
- Hourly actual load
- Generator capacities
- DAFOR

Wind Capacity Value
Loss of Load Expectation (LOLE) Study



Wind Capacity Value
Cumulative Frequency Analysis

Overview:

- Technique of analyzing a set of historical data points (e.g. wind and load to determine wind correlation to peak)
- Determines minimum capacity factor of wind predicted to be available on the system in peak hours, with corresponding certainty

Advantages:

- Analysis is done on top percentage of peak hours, focusing results on key hours for reliability

Disadvantages:

- Does not consider proportion of wind relative to system
- Can produce skewed results from adjacent peaks

Wind Capacity Value
Cumulative Frequency Analysis

Methodology:

- Calculated using Crystal Ball Software and Excel
  - Input load and wind to Crystal Ball and fit to statistical distribution
  - Use confidence intervals to determine percentage of wind estimated to be available during peak load hours

Input Assumptions:

- Top 10% of peak load hours
  - Load in each hour
  - Wind generation in each hour

Wind Capacity Value
Cumulative Frequency Analysis

Confidence Level	Estimated Capacity Value of Wind
95%	4%
90%	8%
85%	12%
80%	16%

As CTs have a capacity value of 90% (10% DAFOR), 90% confidence level was selected.

Wind Capacity Value Conclusions

- LOLE is a robust methodology for calculating wind capacity value
  - However, as 10 – 30 years of data is recommended for accuracy, Cumulative Frequency Analysis provides important validation of LOLE results with a reliability focus
- 2014 IRP Assumption (17% for NRIS wind resources) remains reasonable given the range of LOLE and Cumulative Frequency results
- Incremental wind (above currently planned) will have declining capacity value on the system

ERIS Capacity Contribution
NS Utility & Review Board Order P-880

- P-880, dated May 31, 2005, approved both the Open Access Transmission Tariff (**OATT**) and the Standard (Generator) Interconnection Procedures (**GIP**).
- The OATT Defined the transmission access services offered by NSPI and detailed the prices charged for each service.
- The GIP defined the processes required to interconnect a transmission generating facility to the NSPI Transmission System.

ERIS Capacity Contribution Requirement to Follow the GIP

Market Rules, Section 2.2.6:

1. No new Generating Facility may be Connected to the Transmission System except in accordance with the Standard GIP…

2. No existing Generating Facility Connected to the Transmission System may be significantly modified except in accordance with the Standard Generation Interconnection Procedure…

ERIS Capacity Contribution

GIP: Interconnection Request (IR)

- **IR Application:**

  Includes Deposit(s) / application forms / site control / P.O.I. / 1-line diagram / & Choice of **Energy Resource** Interconnection Service (ERIS) and/or **Network Resource** Interconnection Service (NRIS).

- NRIS and ERIS can be studied concurrently, up to the point when an Interconnection Facility Study Agreement is executed.

ERIS Capacity Contribution ERIS? (GIP 3.2.1)

- The Interconnection Customer (IC) can connect their generation to NSPI's transmission system and deliver their output provided there is capacity on the transmission system to accept it.

- The IC has a right to be connected to the transmission system, but can only use transmission capacity on an "as available" basis.

- ERIS is Energy based service (i.e. **non-firm**).

ERIS Capacity Contribution NRIS? (GIP 3.2.2)

- The IC can connect their generation to NSPI's transmission system and deliver full output in a manner similar to how NSPI integrates its generating facilities to serve native load customers.
- Transmission system Network Upgrades needed to allow full output are identified in the SIS and are built prior to Commercial Operation of the generation facility.
- NRIS is capacity based service (i.e. **firm**).

ERIS Capacity Contribution NRIS Vs ERIS

- ERIS is **non-firm** (energy based).
- NRIS is **firm** (capacity based).
- ERIS permits generation to be installed in locations where NRIS network upgrades might be too costly.
- ERIS facilities can be curtailed due to transmission system constraints.
- Both ERIS and NRIS facilities can be curtailed where system security is in jeopardy.

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ERIS Capacity Contribution
Can an ERIS Generator become NRIS?

Yes, but…

- A new IR would be required.
- The IR must be submitted by the facility owner.
- A new IR Queue position would be assigned.
- New SIS / FAC studies would be conducted to account for any new generation; system changes; and projects higher in the interconnection queue.
- The ERIS GIA would need to be amended to NRIS.

ERIS Capacity Contribution

Can this be expedited?

- The interconnection process can be expedited for small generating facilities (i.e., no Feasibility, combine SIS/FAC, no SIS stability analysis)
- Non-material changes to the generating site are permitted where the POI is not changed and site capacity does not increase by > 10%.
- Any change or addition is treated as a new interconnection request subject to the GIP unless shown to be non-material.

ERIS Capacity Contribution GIP ERIS → NRIS Workflow

- Interconnection Request *(ERIS to NRIS)*
- Scoping Meeting
- Feasibility Study *(not required)*
- Progression Milestones met by IC *(Queue Entry)*
- Combined SIS / FAC
- Generator Interconnection and Operating Agreement (GIA) amendment *(for NRIS)*
- Timeline ~ 6 months
- Deposits / Construction of Network upgrades

ERIS Capacity Contribution
Nuttby: ERIS to NRIS?

- Application was made for SIS
- Application requirements currently under review
- NS Power examining value of conversion of ERIS to NRIS
- Cost of system study, may require system upgrades, etc.

- Board letter: "The objective is not necessarily to determine how a facility can be reclassified from ERIS to NRIS, but to determine how much of its capacity could be counted as a contribution during the winter peak period."

ERIS Capacity Contribution Conclusions: Why can't ERIS be firm?

- ERIS generator may not be able to provide energy based on GIA (may be curtailed due to transmission constraints)
  - Must be able to count on firm capacity as discussed in capacity planning section in order to serve system firm peak
- The nature of an ERIS service is energy-based; it is by definition non-firm, as defined in the OATT
  - In order to ensure we can reliably serve customer load and meet our obligation to serve, NS Power must only count firm generation resources in its capacity planning