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LIST OF ABBREVIATIONS

2026-2026 GRA	2026-2027 General Rate Application
AA	Actual Adjustment
A&G	Administrative and General
AAR	Annually Adjusted Rates
ACE	Annual Capital Expenditure
ADMS	Advanced Distribution Management System
AMI	Advanced Meter Infrastructure
AMIG	Asset Management in Generation
AFUDC	Allowance for Funds used During Construction
AO	Administrative Overhead
ARO	Asset Retirement Obligations
ATL	Above-the-Line Customer Classes
BA	Balancing Adjustment
BCF	Base Cost of Fuel
Board	Nova Scotia Utility and Review Board
BPTC	Best Practices Transmission Committee
BSC	Balanced Score Card
BTL	Below-the-Line Customer Classes
BUTU	Wholesale Market Backup/Top-up Tariff
CA	Consumer Advocate
CAD	Canadian Dollars
CALP	Climate Action Leadership Program
CDD	Cooling Degree Days
CEM	Customer Energy Management
CEATI	Centre for Energy Advancement Through Technological Innovation
CFFO	Cash Funds from Operations
CIP	Critical Infrastructure Protection
CO ₂	Carbon Dioxide
CO _{2e}	Carbon Dioxide Equivalent
COMFIT	Community Feed-in Tariff
COS	Cost of Service

COSS	Cost of Service Study
CRA	Canada Revenue Agency
CWIP	Construction Work in Progress
DCRR	DSM Cost Recovery Rider
DDA	Decarbonization Deferral Account
DER	Distributed Energy Resources
DR	Demand Response
DSM	Demand Side Management
EAM	Enterprise Asset Management
E1	EfficiencyOne
ECEI	Eastern Clean Energy Initiative
EGCCRA	Environmental Goals and Climate Change Reduction Act
EGSPA	Environmental Goals and Sustainable Property Act
ELIADC	Extra-Large Industrial Active Demand Control
ERIS	Energy Resource Interconnection Service
ERP	Enterprise Resource Plan
ESRP	Emergency Services Restoration Plan
EV	Electric Vehicle(s)
F&PP	Fuel and Purchased Power
FAM	Fuel Adjustment Mechanism
FCR	Fixed Cost Recovery
FFO	Funds from Operations
FHP	Fuel Hedging Plan
FLG	Federal Loan Guarantee
FSP	Fuel Stability Plan
FTE	Full-Time Equivalent
FX	Foreign Exchange
GBV	Gross Book Value
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GPS	Global Positioning System
GRA	General Rate Application

GRLF	Generation Replacement and Load Following
GW, GWh	Gigawatt(s), Gigawatt hour(s)
HDD	Heating Degree Days
HFO	Heavy Fuel Oil
Hg	Mercury
HR	Human Resources
IBEW	International Brotherhood of Electrical Workers
INP	(Sydney) International Pier
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IG	Industrial Group
IT	Information Technology
IVR	Interactive Voice Response
kW, kWh	Kilowatt(s), Kilowatt hour(s)
LED	Light-Emitting Diode
LFO	Light Fuel Oil
LMS	Learning Management System
LIIR	Large Industrial Interruptible Rider
LRS	Licensed Retail Supplier
MEU	Municipal Electric Utility
MOS	Management Operating System
MW, MWh	Megawatt(s), Megawatt hour(s)
NBV	Net Book Value
NO _x	Nitrogen Oxides
NM, NEM	Net Metering, Net Energy Metering
NRIS	Network Resource Interconnection Service
NSPEMI	NS Power Energy Marketing Inc.
NSEB	Nova Scotia Energy Board
NSR	Net System Requirement
O&M	Operations & Maintenance
OATT	Open Access Transmission Tariff
OM&G	Operations, Maintenance & General

OT	Overtime
OTE	Overhead Transmission Equipment
PCB	Polychlorinated Biphenyls
PCR	Program Cost Recovery (for DSM)
PHB	Port Hawkesbury Biomass Plant
PLT	Powerline Technician
POA	Plan of Administration
PPA	Power Purchase Agreement
PPE	Property, Plant & Equipment
PTMT	Point Tupper Marine Terminal
PUA	Public Utilities Act
R/C	Revenue to Cost ratio
RES	Renewable Electricity Standards
RFP	Request for Proposal
ROE	Return on Equity
RRQ	Revenue Requirement
RtR	Renewable to Retail
RSP	Rate Stability Plan
SAE	Statistically Adjusted End-Use (Model)
SBA	Small Business Advocate
SCRR	Storm Cost Recovery Rider
SDGA	Sustainable Development Goals Act
SMOC	Smart Meter Operations Centre
SO ₂	Sulphur Dioxide
T&D	Transmission and Distribution
TDC	Total Direct Compensation
Tidal FIT	Tidal Feed-in Tariff
TVP	Time Varying Pricing
TW, TWh	Terawatt(s), Terawatt hour(s)
USD	United States Dollars
WACC	Weighted Average Cost of Capital

Appendix 03A – Status of 2023-2024 GRA Directives

Information about each directive is found below. A status summary table is provided at the end of this Appendix.

1. Storm Cost Reporting

The directive related to storm cost reporting is at para. 332 of the Board's 2023-2024 GRA Decision:

[T]he Board directs NS Power to submit annual reports summarizing actual storm restoration costs for each year of the trial period. This reporting is to include a summary of actual Level 1, 2, 3 and 4 storm restoration costs. It shall indicate the monetary amount of any Level 1/2 and Level 3/4 cost underruns or overruns from base rate allowances. These annual reports shall be submitted by April 1 of each year in 2024, 2025 and 2026. At the end of the three-year trial period, the reports will be used to help assess the effectiveness and equity of the Storm Rider, whether the Storm Rider remains in the best interest of ratepayers and whether adjustments to its construct are required.

NS Power filed its first Storm Cost Report (for 2023) on April 2, 2024, and filed its 2024 Storm Cost Report on April 1, 2025. The 2025 Storm Cost Report will be filed in April 2026.

2. Storm Rider and Stakeholder Engagement

The Board issued the following directive with respect to filing its application for a Storm Rider and the stakeholder engagement for agreement on the presentation of materials at para. 338 of the 2023-2024 GRA Decision:

Therefore, the Board finds that when NS Power submits a Storm Rider cost recovery application for Board approval, it is appropriate for the assessment of the application to include a full review of all storm restoration costs (including capital expenditures), storm hardening costs and vegetation management costs during the related year. The Board directs NS Power to include full detail on all these costs in each Storm Rider cost recovery application submitted during the three-year trial period. In advance of the first Storm Rider cost recovery application, the Board further directs NS Power to engage with stakeholders to determine the specifics for how this information is to be presented.

Compliance with this directive is ongoing. NS Power filed its first Storm Rider Application in 2024 (for 2023 storm costs) following consultation with stakeholders about how the information is to be presented. As there was only one Level 3 storm and no Level 4 storms in 2024, NS Power is not filing a Storm Rider application for recovery in 2026. If NS Power incurs OM&G storm restoration

and recovery above the level in base rates for 2025, it may choose to make an application in 2026 for recovery in 2027. That will complete NS Power's compliance with the Board's directive concerning the Storm Rider arising from the 2023-2024 GRA.

3. Climate Change Adaptation Plan

The Board's directive about the Climate Change Adaptation Plan is found at para. 340 of the 2023-2024 GRA decision:

It is not clear to the Board whether the items identified by NS Power in its response to [NSEB] IR-171 are part of a formalized Climate Change Adaptation Plan adopted by the Company. The Board considers that the implementation of such a plan, through a consultative process, may be useful in demonstrating the prudence of storm restoration costs in Storm Rider cost recovery applications, would engender confidence in such a rider if NS Power seeks to implement one after the period covered by the GRA Settlement Agreement, and would enhance NS Power's capital expenditure processes and integrated resource planning. As such, NS Power is directed to engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025. As with the COSS and Line Loss Study discussed later in this decision, the Board approves the deferral of the costs of developing this plan for recovery through rates after NS Power's next general rate application.

NS Power created a Climate Adaptation Plan in April 2021 guided by Electricity Canada's Climate Change and Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada. The Company has been working with the Climate Action Leadership Program (CALP) to develop its Climate Adaptation Plan (planning process, adaptation strategies and research and innovation) and has provided updates and presentations regularly since 2022.

In addition, NS Power continues to engage with electric utilities and other stakeholders to ensure its proactive approach to climate adaptation is aligned with and/or leading industry practices. NS Power is engaged with Electricity Canada's Climate Change Adaptation Committee where climate adaptation-related work is discussed and shared with other Canadian utilities. NS Power is also working with Electricity Canada's Best Practices Transmission Committee (BPTC), who have been drafting the Utilities Wildfire Mitigation Best Management Practices Guide. In addition, NS Power is a member of several groups with the Centre for Energy Advancement Through Technological Innovation (CEATI), such as the Asset Management in Generation (AMIG), Overhead Transmission Equipment (OTE) group and the Vegetation Management group that discuss and collaborate on various climate adaptation best practices, such as wildfire mitigation plans. CEATI has representation from utilities across North America and internationally. NS Power also contributes to the

development of standards through the Canadian Standards Association (CSA) which is incorporating climate risk into its standards, including those which guide distribution system design.

On March 27, 2025 NS Power provided an update at a CALP technical conference to which some of the regulatory intervenors (the Consumer Advocate (CA), Small Business Advocate (SBA) and Industrial Group (IG)) were invited.

NS Power's final Climate Change Adaptation Plan and Wildfire Mitigation Guide are being filed as **Appendix 3B and 3C** to this GRA filing.

4. DSM True-Up

The Board's directive is found at para. 359 of the 2023-2024 GRA Decision:

As the issue of DSM true-up for prior period variances was not addressed in the GRA Settlement Agreement, the Board makes no determination at this time. The Board assumes that NS Power and stakeholders will continue to discuss this issue and directs that an update on this matter be filed no later than the first application to adjust the DCCR approved in this decision.

NS Power filed its first Demand Side Management Cost Recovery Rider (DSM Rider) application on September 29, 2023 and the historical DSM true-up for prior period variances was addressed by NS Power as part of M11352 proceeding. NS Power considers this item complete.

5. Cost of Service Study and Line Loss Study Stakeholder Engagement

The Board's directive is found at para. 367 of the 2023-2024 GRA Decision:

The Board concurs that the COSS and Line Loss Study should be updated to reflect a number of developments impacting NS Power's system since the 2013 COSS, including the greater integration of wind and other renewables, the addition of gas fired generation, the phasing-out of coal fired generation, the use of grid-scale battery storage, the increased reliance on purchased power agreements, and the integration of bundled and unbundled services, among other issues. All other cost allocation methodologies should be reviewed for their continued relevance and application. The Board concludes that this provision of the GRA Settlement Agreement is appropriate and directs the process and timeline as agreed to by the parties. The Board directs that semi-annual progress reports must be filed with the Board starting January 31, 2024.

NS Power has undertaken an updated Cost of Service Study and Line Loss Study. This included an extensive consultation process. In accordance with the Board's directive, NS Power has been filing stakeholder engagement updates every six months since the beginning of 2024.

The Cost-of-Service Study and Line Loss Study are being filed with this GRA and are included in **Appendix 12A, B and C**.

6. Depreciation Study

The Board's directive regarding the depreciation study is found at para. 374 of the 2023-2024 GRA Decision:

The Board agrees that a depreciation study is necessary and directs NS Power to file a depreciation study prior to its next GRA. The Board further directs NS Power to include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process.

As part of the Decarbonization Deferral Account (DDA) process arising from the last GRA, NS Power consulted with stakeholders about the scope of the depreciation study, in accordance with the Board's directive, and included the updated scope as part of its reporting. In accordance with the Board's DDA decision, the Depreciation Study includes NS Power's thermal assets with forecast retirement dates beyond 2030 and includes Trenton 5, International Coal Pier and Steam General assets. Thermal assets to be retired before 2030 are included in the scope of the DDA, but have also been included in the scope of the depreciation study. However, NS Power is not proposing to increase depreciation rates for these assets in accordance with the approved DDA framework.

The Depreciation Study is being filed with this GRA. Please refer to **Section 8 and Appendix 8A**.

7. Exclusion of Part VI.1 Tax Transaction from Regulated Statements

The Board's directive is found at para. 379 of the previous GRA Decision:

The Board agrees that since the Part VI.1 tax deductions and related transactions with Emera are unregulated activities, these items should be excluded from rate base and from the regulated financial statements of NS Power. The Board directs NS Power to exclude all Part VI.1 tax transactions and amounts from its regulated statements in the future, and to adjust for any amounts currently included in the regulated financial statements.

NS Power has complied with this directive.

8. Annapolis Tidal Generation Facility

The Board issued the following directive at para. 387 of the 2023-2024 GRA Decision:

In the Board's opinion, the inclusion of the Annapolis Tidal Generation Facility in NS Power's regulatory amortizations is in direct conflict with the Board's prior decision on that same point. A finding on that proposed accounting treatment is still premature while the matter is being held in abeyance. In the circumstances, the Board does not approve the component of the GRA Settlement Agreement that provides for the regulatory amortization of the Annapolis Tidal plant. The Board directs that the plant remain in property, plant and equipment.

NS Power complied with this directive as part of the 2023-2024 GRA compliance filing. Since that time, NS Power has continued to examine the best course of action for customers regarding this facility. The Company believes it will be demonstrated that decommissioning this facility is the best option for customers and as such, has forecast the retirement of the Annapolis Tidal plant in January 2027 with amortization of the unrecovered net book value of this facility over a ten-year period. As a result, there is \$2.6 million of regulatory amortization associated with this facility included in the Company's forecast 2027 revenue requirement. NS Power expects to file an application seeking approval to decommission this facility in 2026 and recover the remaining net book value over ten years.

9. Low-Income Customer Collections and Arrears

In discussing the need to address concerns about rates for customers, the Board provided the following directive at paragraph 411 of the 2023-2024 GRA Decision:

The proposed review and consultative process has the commitment of NS Power, the Affordable Energy Coalition and the CA. The Board is pleased to endorse this initiative aimed at lessening the impact of power rates on low- and fixed-income residential customers. Accordingly, the Board directs that the three parties engage in a review process to evaluate the impact of the changes approved in 2013, to examine if further changes are needed, and to establish a systematic evaluation methodology that can be applied to future changes to NS Power's Regulations. The Board directs that a report be provided by April 30, 2023.

The CA, AEC and NS Power have formed a working group which has considered issues facing low-income customers and customers who are in arrears or are having difficulty paying their bills. The group meets quarterly and several initiatives have already been successfully implemented. NS Power has filed two reports providing updates of the group's discussions, actions, and initiatives. NS Power looks forward to continued successful engagement with this group.

10. Alternative Treatment of Interruptible Loads

There were four directives arising from the 2023-2024 GRA which relate to the wholesale market, Open Access Transmission Tariff (OATT) and capacity-based ancillary services. The Board directed as follows at para. 478 of the Decision:

As stated earlier, the MEUs' Closing Submission noted their support for Board approval of the GRA Settlement Agreement, but also sought Board approval of the CBAS recommendations proposed by Mr. Marshall. In addition, they stated that the Board should accept these recommendations and they should be used the next time NS Power requests approval of CBAS rates. The MEUs also recommended that NS Power obtain information from NPCC about the terms under which interruptible load is counted toward reserves. In its response in Undertaking U-14, NS Power stated that interruptible load is counted toward 10-minute reserve when the required amount is not available from generation resources. It also stated that planning to interrupt interruptible loads is not a consideration in meeting day-ahead load and reserve requirements. The Board considers there may be some value in alternate treatment of interruptible loads and directs NS Power to explore options with NPCC. In the next GRA, NS Power is directed to file its analysis of cost implications associated with alternative treatment of interruptible loads.

NS Power has addressed this (and the following three) directives in its report and appendices which are contained in **SR-01 Attachment 1e**.

11. Alternative Treatment of -16 MW in AGC

The Board's directive on this item is set out at para. 482 of the 2023-2024 GRA Decision:

Prior to the next GRA, NS Power is directed to explore alternative treatment of the -16 MW requirement and to demonstrate that it is not double charging transmission customers.

NS Power has addressed this directive in its report and appendices which are contained in **SR-01 Attachment 1e**.

12. Wreck Cove Spinning and 10-Minute Supplementary Reserve

The Board addressed this directive at para. 485 of the 2023-2024 GRA Decision:

Regarding the suggestion that Wreck Cove capacity may be over-credited in the 10-minute spinning reserve costs calculation, the Board understands NS Power's evidence to be that the units are utilized for spinning reserve and for 10-minute

supplementary reserve, so the CBAS charges reflect that actual use of those assets. However, considering Mr. Marshall's questioning of the calculation, NS Power is directed to clearly demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization is represented in its calculations.

NS Power has addressed this directive in its report and appendices which are contained in **SR-01 Attachment 1e**.

13. Exclusion of CT Units from 30-Minute Supplemental Reserve

The final directive concerning capacity-based ancillary services is at para. 486 of the 2023-2024 GRA Decision:

Regarding inclusion of less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve, the Board understands NS Power's evidence to be that the CT contribution to that reserve capacity is negligible, so it is not factored into the calculation. Considering that there are currently seven units in service, the Board finds NS Power's explanation to be lacking and directs that a more fulsome explanation be provided, no later than in its next GRA, to justify its position in this matter.

NS Power has addressed this directive in its report and appendices which are contained in **SR-01 Attachment 1e**.

14. Updated FAM Tariff

In the NSEB's Decision and Order for approval of the 2024 FAM AA/BA Rider, the Board directed NS Power to amend the FAM Tariff language to account for the transition of customers moving both to and from FAM rates. Para. 52 of the 2024 FAM AA/BA Decision provides the following directive:

The Board also directs NS Power to amend the FAM tariff language to account for the transition of customers both from FAM rates and back into FAM rates. These amendments should be provided to the Board for approval no later than in NS Power's next general rate application.

The FAM Tariff has been updated in accordance with the Board's directive and is included in PR-01 Attachments 1S and 2S (FAM Tariff) and the change has also been reflected in the Plan of Administration as described in **Section 6.0 and included in Appendix 6B**.

15. WACC and AFUDC Methodology

The Board rendered its decision on NS Power's 2025 Weighted Average Cost of Capital (WACC) and Accumulated Funds Used During Construction (AFUDC) on March 21, 2025. In the decision, the Board made the following comments and directive:

The Board notes that it has been ten years since the last full review of the methodology and that a broader review would be appropriate for the 2026 application. The Board considers several issues warrant a broader discussion. These include:

- potential alternative forecast methodologies for the short-term rate, the timing of available information and the ability to shorten the forecasting process;
- the use of the opening and closing debt balances to calculate the short-term interest rate, versus using monthly balances;
- other broad issues or methodologies that NS Power and Intervenors feel appropriate to discuss.

The Board is cognizant that there may not be an alternative methodology that is both more reliable and administratively easier than the current approach. However, due to the length of time since the last review, the Board directs NS Power to analyse and report on the current methodology and potential alternatives, including their reliability, ease of administration and any other advantages and disadvantages that NS Powers [sic] considers will provide a robust measure of WACC/AFUDC. This review should be included as part of the 2026 WACC and AFUDC Rates Application. If NS Power submits a General Rate Application (GRA) before it submits its 2026 WACC and AFUDC Rates Application, the review should be included as part of the GRA submission.

Please see NS Power's response below:

Materiality:

The majority of NS Power's capital structure has a fixed cost and does not require forecasting as equity is at the Board-approved rate and the cost of long-term debt is known, apart from forecast new issuances during the forecast period. As a result, the forecasting process for

WACC is primarily an exercise of forecasting the Company's cost of short-term debt. The proportion of the Company's overall capital structure financed using short-term debt is 4.1 percent in 2026 and 4.8 percent in 2027 as shown in FO-10. This means changes in the forecast short-term interest rate have a relatively small impact on the Company's overall WACC/AFUDC rate. As an example, an increase of 0.25 percent in the short-term debt rate would increase the WACC rate by 0.01 percent in 2026 and 2027, indicating the short-term debt rate is not a significant driver of the WACC rate, and the impact of changes in methodology would not be material.

Forecast methodologies:

The Company has adopted a practical approach to forecast short-term interest rates which relies on market-based consensus estimates of Canadian Treasury bills (T-bills) as published by reputable institutions. The Company relies upon the forecasting methodologies and opinions of experts to determine the interest rates, which are then incorporated into the Company's budget. The approach is transparent for the Board and Stakeholders as the inputs are observable and the assumptions required to be made by the Company are limited. The approach also has a low level of complexity as calculations are prepared by independent experts.

In order to maintain the high level of transparency and low level of complexity, alternative approaches would primarily include the adoption of benchmark rates other than 3-month Canadian Treasury bills and/or the sourcing of forecast interest rates from different financial institutions.

Alternative risk-free benchmark rates, such as the Bank of Canada Overnight Rate, Canadian Repo Rate, and Term CORRA, may be used in the calculation of WACC/AFUDC. These risk-free rates would typically be forecast to increase or decrease in tandem with T-Bills. Since the Company applies a fixed spread to estimate the cost of short-term borrowing, switching to a different benchmark rate would likely have little effect on the Company's WACC/AFUDC rate. As a result, adopting a new benchmark rate does not appear to offer any clear advantage.

The actual cost of borrowing Canadian Treasury bills is determined by the market based upon many factors including market demand, liquidity, and economic conditions. The banks and analysts project future borrowing costs based upon their assumptions regarding many factors, including those above. Their assumptions and the methodologies used can vary, which results in different forecast rates.

In order to improve the quality of interest rate forecasts NS Power has adopted the process of incorporating more data points than those from the five Canadian banks that were used in prior calculations. The addition of more opinions strengthens the average rate forecast because it reduces the impact of any potential outliers.

However, the inclusion of more data points will increase the effort required to compile forecasts. The adoption of the Bloomberg consensus rate allows for access to more data points while also reducing the manual effort required to retrieve those data points.

Accuracy of Rate Forecasts

The consistent and accurate prediction of interest rates is not achievable. Analysts provide forecasts which are supported by detailed research and analysis. However, these analysts cannot consistently predict future interest rates with a high degree of accuracy. An analysis over a short period of time, such as 2022 to 2025, may demonstrate that one group of analysts prepares better estimates than another for that period, but does not prove one group to be more accurate or reliable than the other in the long-term.

The Company produced a comparison of the interest rate forecast showing the difference between the Bloomberg consensus rate, the Board approved methodology, and the actual rate for the years 2022 to 2025. This analysis was requested by the Board to demonstrate which methodology was more reliable. The result did not show either methodology to be more accurate than the other. Interest rates were volatile during this period and regardless of the methodology used, there would have been variances between the forecast and actual rates achieved.

The Company has limited ability to improve the reliability and accuracy of the interest rate forecasts. The Company can only include more forecast rates and include high-quality, reputable sources of information.

The historical approach relied upon five data points which were from reputable sources. The sample size of five does present a risk of outliers and bias skewing the results. The Bloomberg consensus rate allows the Company to increase the number of bank opinions included in the sample without adding additional effort required in tracking those estimates.

Timing and Shortening the forecast process:

The Company's Budget is prepared on an annual basis in August/September. After internal review and approval of the Budget, the Company uses the budgeted financial information to prepare the WACC/AFUDC calculation which is filed with the Board in November.

The Budget obtains the necessary information required to determine the forecast opening and closing short-term debt, long-term debt, and common equity balances. The Budget also contains forecast interest rates which are used to determine the cost of debt financing.

The Company recommends Budget figures continue to be used for the purposes of calculating WACC/AFUDC.

Use of opening and closing debt balances

The Company forecasts the annual cost of short-term debt using the forecast borrowing at the end of the month multiplied by the forecast short-term interest rate applicable to the quarter. The annual cost is then divided by the simple average of the opening and closing debt balance for the year. The use of a simple average debt balance can result in a Cost Pre-Tax Factor which is greater or lesser than the quarterly interest rate forecasts.

The Company uses a simple average of the opening and closing debt and equity balances to determine the average capital figure in FOR-10. The simple average calculation is consistent with the approach used to calculate rate base in standardized filing RB 2-16. Therefore, for presentation purposes the Company would recommend maintaining a simple average to calculate the average capital such that average rate base figure in RB 2-16 continues to agree with the average capital figure in FOR-10.

The Company proposes, going forward, that the Pre-Tax Factor used in the WACC/AFUDC calculation would be determined by dividing annual interest expense by the 12-month average of short-term debt (January-December). This approach would ensure the short-term rate presented is a weighted monthly average of the quarterly interest rate forecasts. The table below shows the impact of this proposed change in approach on the Company's estimated cost of short-term debt and WACC rate for 2025-2027.

2026

A. Simple Average of short-term debt outstanding- \$230.3 million

B. Twelve-month Average of short-term debt outstanding- \$280.9 million

C. Interest on short-term debt- \$9.5 million

Simple Average cost of short-term debt (C/A)- $\$9.5 \text{ million} / \$230.3 \text{ million} = 4.14\%$

Twelve-month Average of short-term debt (B/C)- $\$9.5 \text{ million} / \$280.9 \text{ million} = 3.40\%$

2027

A. Simple Average of short-term debt outstanding- \$284.3 million

B. Twelve-month Average of short-term debt outstanding- \$336.5 million

C. Interest on short-term debt- \$10.9 million

Simple Average cost of short-term debt (C/A)- $\$10.9 \text{ million} / \$284.3 \text{ million} = 3.85\%$

Twelve-month Average of short-term debt (B/C)- $\$10.9 \text{ million} / \$336.5 \text{ million} = 3.25\%$

	Short-Term Debt, Cost Pre-tax		WACC Rate, Pre-tax Cost	
	Simple Avg. (Current)	12-Month Avg.	Simple Avg. (Current)	12- Month Avg.
2026	4.14%	3.40%	6.59%	6.56%
2027	3.85%	3.25%	6.50%	6.47%

Status Summary of 2023-2024 GRA Directives

Directive	Status
a. Submit annual reports on April 1, 2024-2026 summarizing actual Levels 1-4 storm restoration costs for each year of the Storm Rider trial period [para. 332]	Ongoing 2024 Filing: M11631 2025 Filing: M12188
b. Include full detail on all storm restoration, storm hardening and vegetation management costs (including related capital expenditures) in each Storm Rider cost recovery application submitted during the three-year Storm Rider trial period. Also, NS Power is to engage with stakeholders to determine the specifics for how this information is to be presented, in advance of the first Storm Rider cost recovery application; [para. 338]	Ongoing 2025 Storm Rider M11692 Consultation complete.
c. Engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025; [para. 340]	In progress
d. File an update about a DSM true-up for prior period variances no later than the first application to adjust the DSM Rider approved in this decision; [para. 359]	Complete
e. File semi-annual progress reports about the stakeholder engagement process for the Cost of Service and Line Loss Studies, starting January 31, 2024; [para. 367]	Ongoing 2024 Filing: M11475 2025 Filing: M11475
f. File a depreciation study before its next GRA and include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process; [para. 374]	In progress Scope of depreciation study determined in M11220
g. Exclude all Part VI.1 tax transactions and amounts from regulated statements in the future, and adjust for any amounts currently included in the regulated financial statements; [para. 379]	Complete
h. Keep the Annapolis Tidal Generation facility in property, plant and equipment; [para. 387]	Confirmed
i. Engage in a review process, with the Affordable Energy Coalition and the Consumer Advocate, to evaluate the impact of the changes approved in 2013 to bill payment, credit and collection matters, to examine if further changes are needed, and to establish a systematic evaluation methodology that	Complete Low-income working group ongoing. 2023 Report: M11349 2024 Report: M11984

Directive	Status
can be applied to future changes. NS Power to file a report by April 30, 2023.	
j. Explore options with NPCC about alternative treatment of interruptible loads and file analysis of cost implications in the next GRA; [para. 478]	Complete SR-01 Attachment 01(e)
k. Explore, prior to the next GRA, alternative treatment of the -16 MW requirement in AGC and to demonstrate that it is not double charging transmission customers; [para. 482]	Complete SR-01 Attachment 01(e)
l. Demonstrate, no later than the next GRA, how the spinning reserve and 10-minute supplementary reserve utilization for Wreck Cove is represented in CBAS calculations; [para. 485] and	Complete SR-01 Attachment 01(e)
m. Provide a more fulsome explanation, no later than the next GRA, to justify the position to exclude CT units from costing of 30-minute supplemental reserve for CBAS calculations. [para. 486]	Complete SR-01 Attachment 01(e)
n. Analyse and report on the current [WACC/AFUDC] methodology and potential alternatives, including their reliability, ease of administration and any other advantages and disadvantages that NS Powers [sic] considers will provide a robust measure of WACC/AFUDC. This review should be included as part of the 2026 WACC and AFUDC Rates Application. If NS Power submits a General Rate Application (GRA) before it submits its 2026 WACC and AFUDC Rates Application, the review should be included as part of the GRA submission.	In progress To be included in GRA process, possibly in response to IRs



CLIMATE ADAPTATION PLAN

Building Climate Resiliency, Revision 1

Abstract

Climate change is bringing more frequent extreme weather events to Nova Scotia, and we need to continue to adapt our infrastructure to withstand the impacts from climate change.

Revision no.	Effective Date	Changes
0	April 8,2021	Document developed
1	April 9, 2025	Updated to reference existing Asset Management System procedures

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Executive Summary

Hurricane Fiona, which arrived in Nova Scotia in the fall of 2022, was the most damaging storm Nova Scotia Power Inc (NS Power) has ever experienced with 415,000 or 80 percent of customers impacted at its peak. At landfall in the province, Fiona was equivalent to a Category 2 hurricane and the wind speeds exceeded more than 220 kilometres per hour. The central pressure of 931 hPa reported during Fiona's landfall was the lowest pressure reported for any storm in Canadian history. Wind gusts over 100 kilometres per hour persisted for four hours in Metro, eight hours in Cape Breton East, and up to thirteen hours in the Northeast region.

NS Power understands that climate change is bringing more frequent extreme weather events to Nova Scotia, and we need to continue to adapt our infrastructure to withstand the impacts from climate change. The goal of this Climate Adaptation Plan is to ensure NS Power continues to successfully deliver on its mission to safely deliver cleaner, affordable and reliable energy to its customers while improving its resilience to climate change risks.

In 2019, the Canadian Electricity Association (CEA, now Electricity Canada or EC) produced a guidance document *Climate Change and Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada*. Nova Scotia Power (NS Power) supported the development of the guide and has now used the guide to inform its Climate Adaptation Plan as described in this document. In doing so, we have met the CEA's aspirational goals for electric utilities to complete their own climate adaptation planning process.

NS Power's Leadership team's commitment to reliability in the face of climate change and will position the utility for readiness and long-term success in a low-carbon world. Although climate change mitigation is a key part of this strategy through decarbonization of the NS Power fleet, the content of this document summarizes NS Power's approach to climate adaptation and preparation for actual and expected future impacts of climate change.

To better prepare for the future, NS Power has obtained climate scenario data that provides insights into the degree of impact that can be expected on its assets and operations. We also commit to continuing to enhance our understanding of the changing climate as more data becomes available and models improve.

To understand and assess the potential risks to NS Power assets from climate change, NS Power is integrating the climate adaptation process into the existing asset risk management process. NS Power asset reliability teams are key to this process and will play a central role across the business to incorporate the potential climate impacts into the annual risk rankings of assets. For NS Power, key climate issues include: extreme weather events; storm surge and sea level rise; changes in seasonal precipitation; and changes in ambient temperatures. These climate-driven issues have the ability to significantly impact NS Power's assets and operations and as such need to be managed proactively and effectively.

To mitigate the impacts from key climate issues, and thus adapt and increase NS Power's resiliency, NS Power will consider the entire suite of approaches to risk mitigation and management. Options will range from ensuring there are critical spares readily available, to longer term options such as re-design, and strategic decisions such as those driven by in-depth asset life assessment. Prioritizing and ultimately selecting one or more options follows the current risk mitigation and management process including development of a business case, now also informed by climate intelligence. Capital projects required to mitigate or manage climate risks will

meet the capital expenditure justification criteria (CEJC), as approved by the Nova Scotia Utility and Review Board.

NS Power recognizes that climate adaptation planning and implementation is a process that must remain flexible and be improved as lessons are learned, and climate forecasting models evolve. We will utilize existing resources and processes to monitor our assets for exposure to climate risks and manage risk as new patterns and information emerge. Accountability for the Climate Adaptation Plan, while led by Enterprise Asset Management, is shared across many levels and functions within NS Power ensuring oversight and review of its implementation. Finally, we commit to systematically improve our climate knowledge through actively collecting climate-related data and using external expertise to better understand future climate conditions in Nova Scotia.

Introduction

The Need for Adaptation Planning

*“Climate change is upon us, and its impacts are getting more severe with each passing year.”*¹ Increases in the intensity, frequency, duration, and geographic reach of extreme weather and changing climatic conditions are the new normal associated with a changing global climate.² Adaptation planning – the process of identifying and prioritizing climate-related physical risks, then selecting and implementing actions to reduce the associated impacts – is fundamental to building resilience in electric utilities today.

NS Power’s adaptation planning process is focused on physical climate change risks and their associated impacts to company assets and operations that can significantly affect an electric utility’s ability to meet its objectives, reliability, and ultimately, the services provided to its customers, as shown in Figure 1.1. Examples include damaged assets such as a flooded generation station associated with a storm surge; changes in the availability of natural resources such as water for hydro generation; and alterations to an asset’s surrounding environment such as changing wind speeds affecting wind turbine generation or changing vegetation management requirements for transmission and distribution assets.

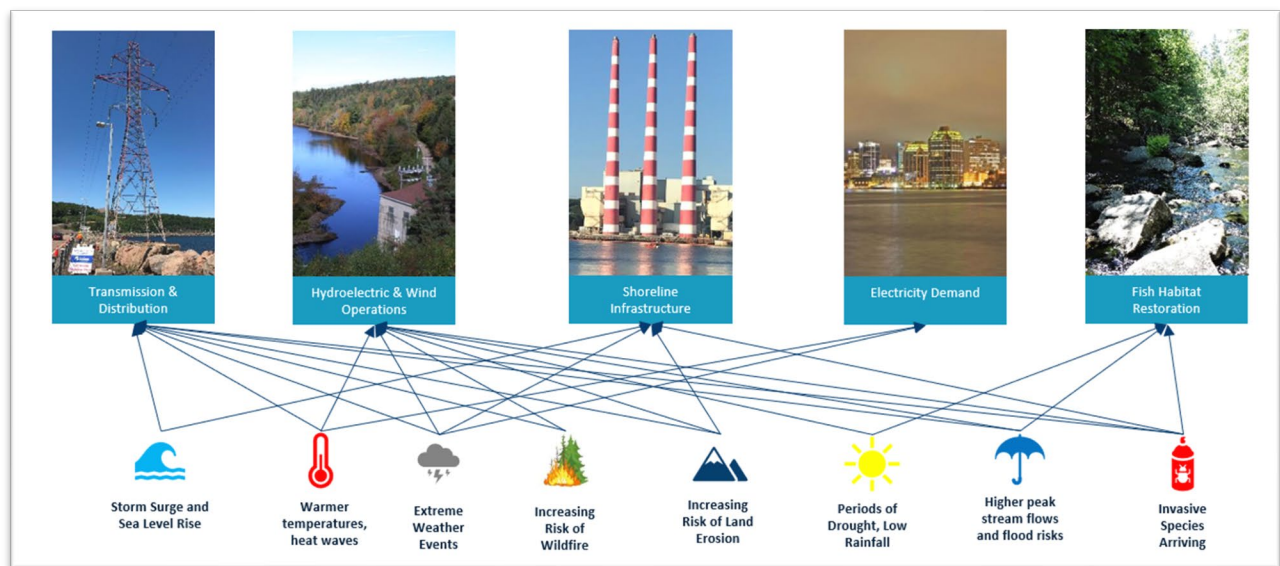


Figure 1.1 NS Power's Linking of Climate Impacts to Assets and Operations

About this Report

Nova Scotia Power Inc. (NS Power) has chosen to utilize the Canadian Electricity Association’s *Climate Change and Extreme Weather: A Guide to Adaptation Planning for Electricity Companies*

¹ Global Commission on Adaptation, “Adapt Now: A Global Call for Leadership on Climate Resilience” (Global Center on Adaptation and World Resources Institute, September 2019)

² Canadian Electricity Association, “Adapting to Climate Change a Risk Management Guide for Utilities” (September 2019)

in Canada³ (CEA Guide) to develop its approach to climate adaptation planning. The CEA Guide outlines eight practical steps for managing risks associated with climate change shown below.

Table 1 CEA's Eight-Step Framework for Developing an Adaptation Plan

Phase of Development	Step in Process
Setting the Stage	Step One: Define objectives and engage leadership
Risk Assessment	Step Two: Identify critical and vulnerable assets and operations
	Step Three: Identify key potential climate impacts
	Step Four: Assess risks to critical and vulnerable assets and operations
Risk Response and Adaptation Planning	Step Five: Identify potential adaptation measures (risk controls)
	Step Six: Develop a business case for selected measures
Preparation for Implementation	Step Seven: Detail and document implementing control actions
	Step Eight: Establish a process to review and improve Plan

Chapter 1 Setting the Stage

NS Power recognizes that climate change is an enterprise risk to utilities and that adaptation planning is a prudent and important risk management strategy. This chapter comprises CEA step one which outlines the reasoning behind this view and how NS Power's goals and objectives support adaptation planning and the planning process.

1. Step 1: Define Objectives and Engage Leadership

The following section lays out the case for treating climate change as an enterprise risk and the need for adaptation planning.

1.1. Nova Scotia Power Inc.

NS Power is a full-service electric utility involved in all aspects of the electricity supply chain – generation, transmission, and distribution – across Nova Scotia. NS Power is a fully owned subsidiary of Emera Inc. and is publicly regulated by the Nova Scotia Energy Board. NS Power generates more than 2,400 megawatts of electricity from a variety of energy sources including hydro, coal, petroleum coke, fuel oil, biomass, natural gas, and wind to service more than half a million residential, commercial, and industrial Nova Scotian customers.

³ Canadian Electricity Association, "Climate Change and Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada" (July 2019)

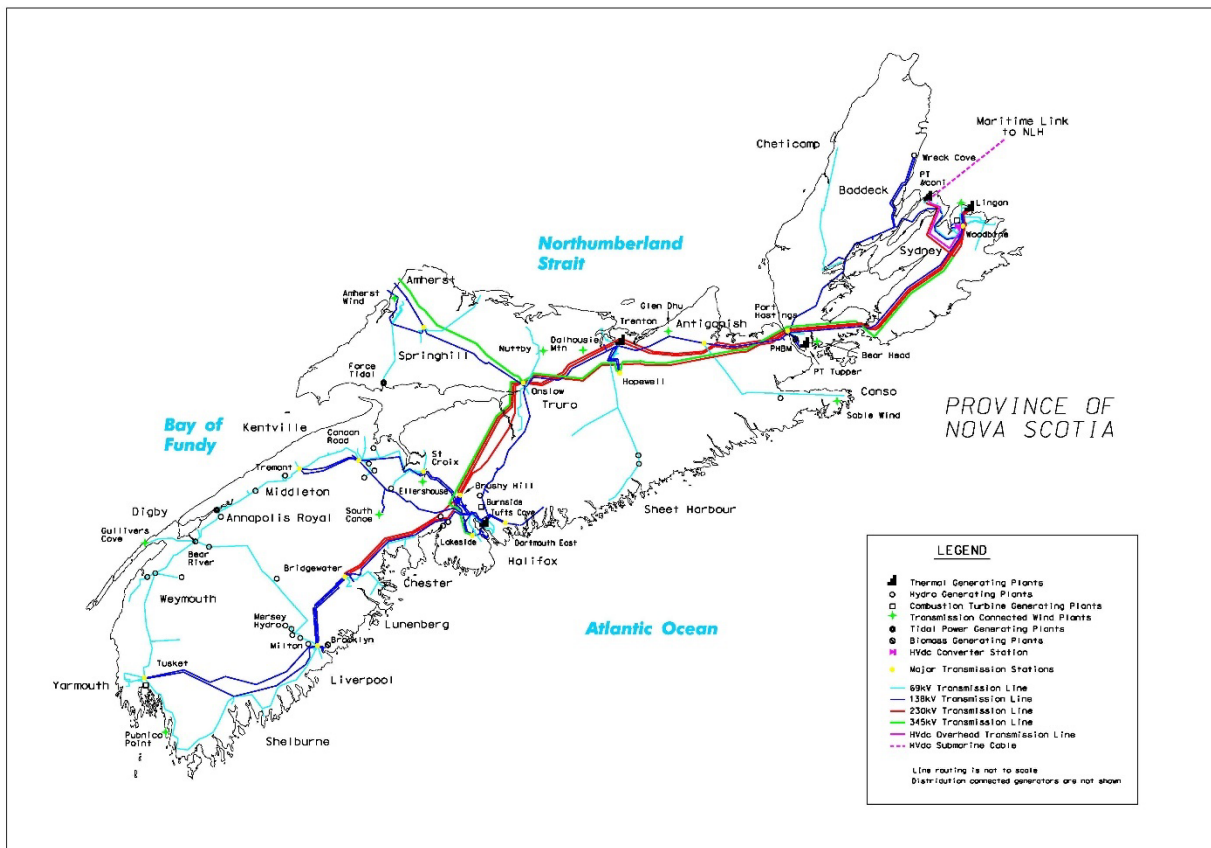


Figure 1.1 Map of NS Power Infrastructure

NS Power recognizes the need for proactive climate change risk management to anticipate, plan for, and respond to the significant effects associated with climate change and extreme weather events that impacts, or is anticipated to impact its \$5 billion electricity infrastructure across the province. As the provider of 95% of Nova Scotia's electricity, NS Power also appreciates its significant responsibility to "...exercise reasonable care in preparing for and responding to...climate change and extreme weather hazards"⁴ to effectively manage the province's electricity system. To protect its financial and physical assets in the long run and ensure its customers can depend on a safe, reliable and cost-effective source of electricity, NS Power is implementing this climate adaptation planning process.

The Strategic Asset Management Plan (SAMP), filed with the Nova Scotia Utility and Review Board on December 16, 2024, outlines Nova Scotia Power's comprehensive approach to managing its assets in alignment with corporate objectives and regulatory requirements. The SAMP emphasizes the importance of leveraging asset management principles to balance performance, risk, and cost, ensuring safe, reliable, and environmentally-sound operation of assets. This plan is crucial for climate adaptation, as it incorporates strategies to address

⁴ Canadian Electricity Association, "Adapting to Climate Change a Risk Management Guide for Utilities" (September 2019)

emerging challenges such as climate change and the integration of renewable energy sources. By utilizing a risk-based decision-making approach, the SAMP supports the development of a resilient and adaptive grid, capable of responding to the increasing frequency and severity of climate-related disruptions. As explained in the subsequent sections, the climate adaptation planning process at NS Power is integrated into the asset management system defined in the SAMP, ensuring a cohesive and comprehensive approach to managing climate risks. This alignment with the climate adaptation plan ensures that NS Power remains committed to providing dependable and efficient power service to its customers while addressing the impacts of climate change.

1.2. Goals and Objectives

The goal of the Climate Adaptation Plan is to ensure the utility continues to successfully deliver on its mission to provide safe, reliable and affordable electricity, while improving its resilience to climate change risks. Climate change threatens this mission with potential damage to or changes in the operation of generation, transmission, and distribution assets used to meet Nova Scotia's electricity needs.

As an electricity sector leader in asset management, NS Power is keenly aware that proactive climate change risk management is a business imperative for Canadian electricity companies and that planned climate adaptation measures can be more effective and lower cost than future reactive repairs or replacements. The objectives below address NS Power's ability to identify climate change risks, maintain the assets on the ground, and lead industry with respect to climate adaptation.

The objectives of the Climate Adaptation Plan are as follows:

- i. Facilitate the identification, evaluation, and prioritization of climate-related risks for NS Power's assets through integration of those risks into existing asset management processes and the organization's enterprise risk management system;
- ii. Enhance NS Power's fundamental capacity to adapt to climate change by leveraging the best climate science and data available to inform decision-making processes;
- iii. Increase organizational resilience by reducing vulnerabilities to the physical impacts of climate change through development of adaptation actions;
- iv. Enhance cross-sectoral collaboration to drive climate adaptation best practices across the electric utilities industry; and
- v. Leverage new business opportunities and innovation across operational, planning, and design measures to adapt to near-, mid- and long-term impacts of climate change.

Scope of Adaptation Planning Exercise

This Climate Adaptation Plan is applicable to all NS Power's physical assets owned or managed by the company associated with generation, transmission, and distribution of electricity in the province of Nova Scotia. This plan excludes the activities of partnerships, and excludes impacts associated with employee health and wellness.

Limitations of Adaptation Planning Exercise

NS Power acknowledges that climate change poses set of risks that is broader than only physical risks, to company assets. While the broader scope is not addressed in this climate adaptation planning exercise, NS Power addresses transition risks⁵, as part of its System Planning functions. Transition risks are addressed in organizational strategic deliverables, such as the Integrated Resource Plan (IRP) and the 10-Year System Outlook (10YSO).

1.3. Leadership Engagement

NS Power's Executive Leadership Team (ELT) and senior management understand that climate change is a risk, influencing how the utility operates. This perspective aligns with NS Power's parent organization, Emera, which has identified climate change as an enterprise risk in its annual Sustainability Report. This adaptation planning process integrates climate change risk and opportunity management into enterprise practices, ensuring accountability to the ELT.

NS Power's forward-looking strategic mandate lays the groundwork for delivery of its purpose and mission.

PURPOSE: Energizing modern life and delivering a cleaner energy future for all Nova Scotians.

MISSION: We are proud to power Nova Scotia. Our customers count on us for safe, reliable and affordable electricity.

The mission is supported by NS Power's 2025 Corporate Strategy, summarizing its business priorities in two core pillars: **Deliver Value for Customers** and **Reliability+**. These pillars demonstrate the ELT's engagement on the topic of climate and will position the utility for readiness and long-term success in a low-carbon world.

ASPIRATIONAL GOALS	Deliver Value For Customers We will be a trusted partner and deliver exceptional service.	Reliability+ We are building a reliable, modern grid that supports electrification.
KEY INITIATIVES	• Customer First Program • Grow our Customer Centric Culture • Personalized customer offerings and self-serve options • Modernized experiences to meet customer expectations • Meet legislated clean energy targets	• Reliability Investments • Electrification Programs • Grid Modernization • Performance Standards • Public Charging Infrastructure • Reliability community engagement • Hydro Investments • Maintain and leverage thermal fleet through clean energy transition

⁵ Transition risks are risks related to the transition to a lower-carbon economy including policy and legal risks, market and technological risks, and reputational risks.

This adaptation planning exercise supports elements of the two pillars as described below:

Pillar 1 (Deliver Value for Customers): We will be a trusted partner and deliver exceptional service.

Adaptation planning will support the provision of a reliable electricity service (reduced outage time), improving customer experience

Enhanced stakeholder engagement and collaboration within the industry will drive improvement in adaptation best practices

New business opportunities and innovation associated with adapting to the changing climate will provide customers with more options

Pillar 2 (Reliability+): We are building a reliable, modern grid that supports electrification.

Adaptation planning will support cost-efficient deployment of services by enabling appropriate assessment of climate risks so maintenance can be prioritized and managed efficiently

Reliability investments, including storm hardening initiatives will enhance the resiliency of the grid.

Grid Modernization initiatives will create a more resilient and adaptive grid capable of responding to the increasing frequency and severity of climate-related disruptions.

Business Case for Climate Change Adaptation

Warming of the global climate system is unequivocal and climate change impacts are expected to intensify in the future. Impacts of warming global average temperatures are wide-ranging and include (but are not limited to) flooding, wildfires, damage to infrastructure, loss of land to rising seas, risk to water supplies, and heat stress. For detailed information about how Canada's climate is changing and what changes are projected in the future, refer to *Canada's Changing Climate Report*.⁶

The World Economic Forum's (WEF) Annual Global Risks Report has shown climate change-related risks among the top five identified risks in terms of likelihood and impact since 2012. In the 2021 report, all five top risks by likelihood and four top risks by impact involved climate change including climate action failure, extreme weather, and biodiversity loss. The World Energy Council reports that from 1980 to 2014 there was a four-fold increase in extreme weather events affecting global energy infrastructure.⁷ Addressing growing climate risks has become a global imperative and "...adaptation must become part of the 'new normal'."⁸

Weather versus Climate:

Weather refers to the actual atmospheric conditions over a short period of time (i.e., hours, days), while climate refers to weather patterns experienced across a region over longer time periods, typically 30 years.

Extreme weather refers to events such as floods, droughts, snow and thunderstorms that are rare (i.e., in the bottom or top 10% of severity for a given event) for the season and region where they occur.

⁶ B Bush, E. and Lemmen, D.S., editors, "Canada's Changing Climate Report" (Government of Canada, 2010)

⁷ World Energy Perspective, "The road to resilience – managing and financing extreme weather risks" (The World Energy Council, 2015)

⁸ Canadian Electricity Association, "Climate Change and Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada" (July 2019)

Adapting to the changing climate is not an alternative to increasing action to slow climate change, but adaptation has become a crucial complement to the effort. The Global Commission on Adaptation recently made the economic case for adaptation having found that “...the overall rate of return on investments in improved resilience is very high, with benefit-cost ratios ranging from 2:1 to 10:1, and in some cases even higher”⁹.

Planning for adaptation can provide NS Power multiple benefits including avoided economic losses associated with reduced system outage time and infrastructure repair/replacement, as well as improved efficiencies associated with climate risk-based system maintenance.

Climate Change as an Enterprise Risk for Utilities

The electric utilities sector is being significantly impacted by physical effects of climate change. The Intergovernmental Panel on Climate Change (IPCC) reports that the electricity sector is one of the sectors most at risk of disruption from physical impacts associated with acute and chronic climate risks. Both acute and chronic risks can cause direct (i.e., damaged assets) and indirect (i.e., disrupted fuel supply to generating stations) climate impacts. In fact, many chronic risks such as increased temperature swings and water scarcity can be as impactful as more severe, yet less frequent, acute risks.

Acute disruptions are individual events such as increasingly unpredictable, volatile, and extreme weather events (i.e., hurricanes, floods) that damage, for example, generation, transmission, and distribution assets.

Chronic risks refer to longer-term shifts in climate patterns, for example, gradual temperature and precipitation changes altering the availability of key resources such as meltwater for hydro generators or sea level rise.

NS Power owns and operates most of the generation, transmission, and distribution assets in Nova Scotia. Much of this was designed and built to standards that did not consider the currently projected climatic conditions. Climate change is manifesting across this portfolio of assets as numerous acute and chronic risks. Progression of climate change is therefore an enterprise risk.

It is now necessary to consider anticipated direct and indirect physical impacts from climate change in adaptation planning to ensure the integrity of the electricity system.

Table 1.1, below presents some examples of the types of physical climate risk-related impacts expected for Canadian electric utilities such as NS Power.

Table 1.1: Physical Climate Risk-Related Impacts for Canadian Electric Utilities¹⁰

Affected Business Operation	
Electricity Generation	Transmission & Distribution
Damage to facilities and infrastructure (generating stations, wind turbines, equipment, buildings, etc.) from extreme weather (ice, wind, hail, etc.)	Damage to overhead wires and equipment due to high winds, ice loading, and accretion
Damage to coastal infrastructure due to sea level rise and storm surge causing inundation and flooding	Inundation and physical damage to transmission, distribution assets and transportation infrastructure enabling access from flooding, landslides, and erosion (poles, wires, roads)

⁹ Global Commission on Adaptation, “Adapt Now: A Global Call for Leadership on Climate Resilience” (Global Center on Adaptation and World Resources Institute, September 2019)

¹⁰ Natural Resources Canada, “Adaptation State of Play Report” (2017)

Affected Business Operation	
Electricity Generation	Transmission & Distribution
Uncertainty for hydro generation due to changes in streamflow volume and timing	Damage to power lines and substations at risk from sea level rise
Increased flood risk affecting assets (buildings, vehicles, etc.) and infrastructure (roads, bridges, etc.)	Coastal storms threaten infrastructure and can damage coastal roads, preventing maintenance access to coastal transmission and distribution assets
Infrastructure impacts (e.g., on spillways) and dam failure/safety from extreme precipitation and flooding	Wildfires threaten wooden transmission poles, substations, and other infrastructure

While climate change poses many risks, adapting to physical climate risk also creates opportunities for Canadian electric utilities. As efforts to meet climate targets accelerate, some opportunities that may be available to utilities such as NS Power include:

- New product and service offerings such as distributed energy resources and services associated with EV charging stations;
- Implementation of energy storage solutions to reduce peak consumption levels and limit the impact of system outages to customers; and/or
- Increases in electrification as the customer base chooses non-emitting electricity to replace fossil fuel-based energy use in, for example, building and water heating and transportation.

An example, the Smart Grid Nova Scotia Project, as detailed in our regulatory filings with the Nova Scotia Utility and Review Board, highlights our commitment to modernizing the grid. This project includes the deployment of advanced technologies and infrastructure improvements to enhance grid resilience and reliability, further supporting our climate adaptation efforts.

Electric utilities that choose to seize the opportunities associated with climate change will be better positioned for success in the future.

1.4. Understanding Climate Adaptation Versus Climate Mitigation

While NS Power is a leader in climate change mitigation, adaptation is still needed

NS Power has achieved the fastest transition to cleaner energy among Canadian utilities and is on track to achieve its target of supplying 80% of its energy from renewable sources by 2030.

NS Power's 18% integration of wind generation is among the highest in North America. This has supported NS Power's 54% reduction in CO₂ levels since 2005, exceeding Canada's target in the Paris Agreement.

Climate change adaptation refers to being prepared for actual and expected future impacts of climate change.¹¹ It includes processes to identify and implement actions to moderate and/or reduce harm associated with a changing climate, such as safeguarding electricity assets. Climate mitigation refers to reducing greenhouse gas (GHG) emissions from human activities such as reducing fossil fuel consumption. Global warming will continue for many decades due to feedback mechanisms in the global climate system.¹² Therefore, dealing with climate change requires both

¹¹ Adapted from IPCC, Annex II Glossary, https://www.ipcc.ch/site/assets/uploads/2018/02/AR5_SYR_FINAL_Annexes.pdf

¹² Canadian Electricity Association, "Adapting to Climate Change a Risk Management Guide for Utilities" (September 2019)

adaptations to address the locked-in climate change effects and mitigation to reduce or halt even greater climate change impacts.

Incorporating adaptation processes into electricity system planning and maintenance supports the proactive management of risk and can help boost resilience to long and short-term impacts of a changing climate.

1.5. Importance of Scenario Analysis for Understanding and Managing Climate Change

To better prepare for the future, electric utilities require data that can provide insights into the degree of impact that can be expected on their assets and operations. Credible data can help prioritize business activities and strategic planning in the short-, medium-, and long-term. However, the path that climate change will take is dependent on many factors, including but not limited to public policies, technological advancements, and population behaviour. To gain insight on the multiple possible paths, scenario analysis is recommended.

Scenarios consider different combinations of climate-related risks and provide insight for companies to assess how each risk may affect them financially, strategically, and operationally. Examples of scenarios commonly used by electric utilities to prepare for the impacts of climate change include the Representative Concentration Pathways (RCPs), which have been adopted by the IPCC for physical climate risks, and the International Energy Agency's (IEA's) World Energy Outlook (WEO) scenarios, which are largely focused on transitional climate risks for the energy sector. The RCP and WEO scenarios include a variety of factors, such as stated government policies, projected current climate trends, and assumed different levels of GHG emissions reductions by various target years. It is important to remember that scenario analysis does not attempt to predict the most likely future. Scenarios are intended to model various plausible futures to depict a spectrum of outcomes for organizations to better inform their decision-making.

The IPCC RCP physical climate scenarios were used for the physical climate risk analysis technical study that supported the identification of climate impacts in NS Power's adaptation planning process. The technical study by Acclimatise, *Physical climate risk and prioritisation analysis*,¹³ utilized extensive climate modelling that has been completed by various organizations on global, national, and regional scales to create a substantial database of information on climate variables such as temperature, precipitation, and sea level rise to name a few. Utilities like NS Power can use this data to consider plausible future states based on varying degrees of climate impacts and better manage the uncertainties associated with the changing climate.

NS Power is aware of a new approach utilizing Shared Socioeconomic Pathways (SSPs) adopted by the IPCC for physical climate risks. However, NS Power has not updated any of its climate datasets at this time to incorporate this new approach. It is important to note that the outcomes for new datasets related to Coupled Model Intercomparison Project 6 (CMIP6) and the SSPs would not be significantly different from NS Power's current datasets based on CMIP5 and the RCPs. CMIP5 and CMIP6 are frameworks for coordinated climate model experiments designed to improve global knowledge of climate change.

¹³ Acclimatise, Nova Scotia Power: Physical climate risk analysis, Phase 2 Technical Report (August 2020)

1.6. NS Power's Adaptation Planning Process

In 2019, NS Power began investigating how it might better understand and strategically manage climate-related risks and opportunities. NS Power recognized the potential magnitude of impact that climate change will have on its assets and to the reliability and sustainability of its operations and acknowledged the risk that climate change poses to the successful delivery on its mission and strategic mandate.

In early 2020, NS Power engaged Manifest Climate (formerly Mantle314) for climate risk and adaptation consulting support. Manifest Climate (Manifest) was contracted to deliver a training workshop for engineers and asset management leaders designed to level-set the group's understanding on climate change, its impact on business, on utilities, and on NS Power's assets. Manifest also conducted ten interviews with many of the leaders and engineers that had taken part in the training exercise. The interviews enabled Manifest to gather first-hand information for input to the adaptation planning process about how climate change is impacting NS Power assets and operations today and about potential impacts expected in the future.

In recognition that reliance on historical, experiential, and anecdotal data is insufficient to predict (or fully understand) future climate risk impacts on electricity assets and operations, NS Power leadership also tasked Manifest with identifying and engaging a physical climate risk assessment service provider. Acclimatise was selected to provide climate data analytics expertise and climate modelling services to support the assessment of physical climate change risks to NS Power's electricity infrastructure for the adaptation planning process. For more information about the physical climate risk analysis completed for the adaptation planning study, refer to Manifest's Climate Data Technical Report.¹⁴

¹⁴ Manifest Climate (formerly Mantle314 Inc.), Climate Data Technical Report (Final), Building NS Power's understanding of climate data to inform its risk management process (September 2020)

Chapter 2 Risk/Opportunity Assessment

Building on the industry-wide climate knowledge in Chapter 1, this chapter focuses on NS Power's adaptation plan, comprising on three steps: [Identify Critical Assets and Operations](#) (Step 2); [Identify Key Potential Climate Impacts](#) (Step 3); and [Assess Risks to Critical and Vulnerable Assets and Operations](#) (Step 4). This chapter explains the significant role scenario analysis, the usefulness of prioritization, and how these steps integrate with NS Power's existing risk management for assets.

2. Step 2: Identify Critical Assets and Operations

This section discusses how NS Power classifies its Generation and Transmission & Distribution assets in the context of importance to overall objectives.

NS Power's assets and operations generate more than 10,000 gigawatt hours of electricity each year providing approximately 95% of Nova Scotia's electricity needs. This electricity is delivered to more than half a million residential, commercial, and industrial customers through approximately 5,000 km of transmission and 28,000 km of distribution facilities across the province. This is fundamental to the quality of life in Nova Scotia. NS Power defines the criticality of its electricity system assets on a scale, emphasizing their importance in achieving the mission of providing **safe, reliable and affordable electricity to its customers**.

2.1. Identification of Assets and Operations Critical to NS Power's Mission and Mandate

The assessment and assignment of the Criticality of an asset is fundamental to NS Power's approach to risk evaluation and decision-making. Criticality is defined by the type and magnitude of impact the failure of an asset may have on the organizational goals. The types of impacts considered include:

- Health & Safety – for NS Power personnel, its service providers, and the public
- Environment – effective stewardship of natural resources
- Business Sustainability – Brand/Customer impact, Reliability, Regulatory, Reputation etc.

This concept, utilized in the application of the Asset Management Mechanism, aligns with the matrices included in NS Power's Capital Execution Justification Criteria (CEJC), see Figure 2.1.

NS Power has a comprehensive understanding of the need for rigorous operational management of its assets, and does so, through a strong foundation of asset risk assessments developed by asset reliability teams (for information about reliability teams, see Section 4.1). NS Power utilizes this 1-5 scale, using methodology outlined in the Asset Management System Operating Procedure, Criticality Assessment (NSPI-AMS-002), to define the importance of an asset, with 5 being the most critical.

Health & Safety	Environment	Business Sustainability	Consequence
- Regulatory requirement breached. - Critical safety incident requiring support from external resources - Fatality or Permanent Disability.	- Regulatory requirement breached. - Loss of generating station or facility operating permit. - Critical liquid, chemical or particulate release with off-site or off-facility impact.	Business Sustainability Criticality Ranking is informed through factors such as replacement energy costs, Regulatory Requirements, SAIFI, SAIDI, DAFOR, System Upgrade Requirements, Code Requirements and Project Economics (payback period, NPV, Revenue Requirement).	Critical
- Major safety incident leading to JOHSC actions and controllable by internal resources. - Lost time Injury	- Corporate environmental target exceedance. - Major reportable environmental incident with off-site or off-facility impact.		Major
- Serious safety incident leading to JOHSC actions and controllable by internal resources. - Recordable injury, >1 medical Aid	Serious reportable environmental release causing license exceedance and off-site or off-facility impact.		Serious
- Moderate safety incident controllable by internal resources and no JOHSC actions required. - Recordable injury, < 1 Medical Aid	Moderate reportable environmental release without license exceedance and internal impact only.		Moderate
- Minor safety incident controllable by internal resources and no JOHSC actions required - First Aid Injury	Minor non-reportable environmental release with internal impact only and no license exceedance.		Minor

Figure 2.1: Criticality scale at NS Power from the Capital Expenditure Justification Criteria

3. Step 3: Identify Key Potential Climate Impacts

This section explains how NS Power has increased its knowledge on how climate impacts may develop over time and how they might be prioritized for adaptation. It summarizes the climate scenario data exercise with Acclimatise and Manifest and outlines key variables and data sources. The prioritization method is overviewed along with examples of scenario data applied to assets. The climate scenario data and the prioritization methodology are starting points to help guide the incorporation of climate risks into existing asset management processes including risk assessments.

The objective of Step 3 in the CEA Guide is to identify existing and potential climate impacts that could affect assets and operations critical to the successful delivery of NS Power's mission. To achieve this, NS Power completed the following tasks:

Physical Climate Risk Analysis

- Contracted a physical climate risk service provider, Acclimatise, to conduct a physical climate risk analysis of NS Power's assets; Acclimatise completed the following tasks:
 - Mapped the relevant climate hazards to key climate variables for the physical climate risk analysis exercise;
 - Defined key parameters for physical climate risk analysis;

- Harvested best in class present-day and projected datasets and completed climate data analytics to generate physical climate risk analysis for 100 NS Power critical assets;
- Developed a comprehensive climate dataset to inform NS Power's "asset management mechanism", utilized for risk assessment. For each climate variable included in the physical climate risk analysis, the dataset provides monthly output for:
 - Present-day and projected data;
 - Two warming scenarios, RCP 4.5 and RCP 8.5;¹⁵ and
 - Mean, 5th, and 95th percentiles, in addition, other statistics were provided where identified/requested by NS Power, such as specific temperature thresholds.

Identification of Potential Climate Hazards Associated with Physical Climate Impacts

- Identified and listed the relevant climate hazards¹⁶ that may cause a climate impact based on observed and local knowledge as well as climate information;
- Compiled all available climate data to support identification and assessment of resulting climate impacts using historical, experiential, and anecdotal knowledge gathered within NS Power;
- Completion of asset- or site-specific climate studies, as warranted.

Climate Hazard refers to a potential cause of damage, loss of infrastructure, or service provision associated with climate-related physical events or associated physical impacts

Example Climate Hazards:

Sea level rise, major precipitation event, storm surge, heat wave, water availability, ice storms, wildfires, hurricanes, etc.

3.1. Physical Climate Risk Analysis

The physical climate risk analysis exercise was designed to use the best available climate data to identify the various climate change impacts NS Power might face based on its geographic location and specific infrastructure/assets. The climate data gathered through this exercise will be integrated into asset risk assessments via NS Power's asset management mechanism (see [Step 4](#) for an overview of the mechanism), used to identify the need for risk mitigation, and inform asset-level decisions. The objectives of the exercise were to:

- a) Identify climate risk variables that could materially impact NS Power's assets/operations;
- b) Select future time horizons and warming pathways most applicable to NS Power for near and mid-term planning purposes;¹⁷
- c) Harvest best in-class observed and projected datasets;
- d) Define, where available, relevant operational or maintenance climatic thresholds against which to analyze the climate data and derive additional indices; and
- e) Provide climate data to NS Power's asset reliability teams in a usable format that could be integrated into NS Power's existing risk assessment processes.

¹⁵ Each RCP scenario corresponds to a different global warming scenario.

¹⁶ Appendix 3 of the CEA Guide uses the term "climate impacts" to refer to both climate change phenomena such as sea level rise and the resulting harm to utility infrastructure. For clarity, in this study, we refer to the phenomena (the categories in the first column of the table in Appendix 3) as *climate hazards* and reserve *climate impacts* for the potential changes or damages a utility might experience.

¹⁷ The CEA Adaptation Planning Guide defines "near-term" as the current period until approximately 2040, "mid-term" to the 2040-2070 period, and "long-term" to the 2070-2100 period.

The physical climate risk exercise generated three technical reports that are referenced for more detailed information throughout this plan:

- 1) **Acclimatise Scoping Report** documented Phase 1 of the physical climate risk analysis. The report described the data and modeling framework that was implemented in the second phase of the risk analysis;
- 2) **Acclimatise Technical Report** documented Phase 2 of the physical climate risk analysis. The report detailed the climate data selection and analytics methodology; and
- 3) **Manifest Technical Report** summarized the available climate data and learnings accumulated throughout the adaptation planning exercise to the completion of the physical climate risk analysis. It outlined the limitations of the climate data and modeling, and best practices for use of climate data projections. It also included a hazard prioritization tool, and an Expenditure Level-Adaptation Degree (ELAD) matrix, to aid in navigating the considerable dataset and directing analysis.

Climate Risk Variables

Acclimatise recommended a list of climate variables for which modeling results would provide insight into the physical climate risks that NS Power may be facing. This list was developed based on:

- NS Power's list of relevant climate hazards;
- NS Power's *Climate Master spreadsheet*;
- A list of recent local weather events gathered by NS Power; and
- Acclimatise's own extensive experience working with other electric utilities.

Table 3.1 maps the list of climate hazards from Appendix 3 of the CEA Guide to the corresponding climate variables for the physical climate risk analysis. Note that three of the CEA climate hazards do not have corresponding climate variables, because they are not currently included in climate models. For commentary, please see technical details in Section 8.2 of the Manifest Technical Report.

Table 3.1: Relevant Climate Hazards Mapped to Corresponding Climate Variables

CEA Climate Hazard	Associated Climate Variables
Changes in mean annual and/or seasonal temperature	• Temperature, daily mean • Temperature, daily max • Temperature, daily min
Changes in runoff and ground conditions	• Riverine flooding • Land Slide susceptibility and hazard (rainfall-induced) • Freeze-Thaw cycles
Changes in type, timing and intensity of precipitation	• Total precipitation, daily • Snow fall • %Damage Liquid Precipitation • \$ Damage Solid Precipitation • Standardized Precipitation Index (SPI)
Changes in water availability	• Total precipitation, daily • Standardized Precipitation Index (SPI) • Snow fall

CEA Climate Hazard	Associated Climate Variables
Changes to extent and duration of snow cover (e.g., timing of spring melt), permafrost melt and ice conditions (e.g., deepening of annual thaw)	• Total precipitation, daily • Snow fall • #Days with freeze-thaw cycles • #Days with freezing rain • #Days with wet snow • % Damage Liquid Precipitation • % Damage Solid Precipitation
Drought and wildfire	• Temperature, daily mean • Temperature, daily max • Temperature, daily min • Specific humidity • Fire Weather Index (FWI) • Standardized Precipitation Index (SPI)
Duration of growing season	• Growing Degree Days (Base 10)
Heat waves	• Temperature, daily mean • Temperature, daily max • Temperature, daily min • #Days > 30 °C • #Days > 35 °C
Ice storms and freezing rain	• Wind gust, (daily and annual) • #Days with freezing rain • #Days with wet snow • % Damage Liquid Precipitation • % Damage Solid Precipitation
Major precipitation events, overland flooding and storm surges	• Total precipitation, daily • Sea level rise • Coastal Flooding • Riverine Flooding
Sea level rise	• Sea level rise • Coastal Flooding
Wind events	• Wind gust, (daily and annual) • #Days with gusts > 80 km/h • #Hours with gusts > 80 km/h

*Electrical storms; Pathogens, pests and diseases, Shifts in species range or reproductive patterns for plants and animals are not included in the climate models

Physical Climate Risk Analysis Parameters

For Acclimatise to harvest the most relevant data for NS Power, a number of parameters were needed to provide boundaries for the exercise. These parameters were determined in consultation with NS Power and Manifest and are summarized in Table 3.2. For more detailed information about the study approach or methodology, refer to Sections 7 and 8 of the Manifest Technical Report and Section 6 of the Acclimatise Technical Report.

Table 3.2: Physical Climate Risk Analysis Parameters Summary

Analysis parameter	Value	Notes
Baseline period	2000-2019 (present day)	This timeframe is centered on the year 2010 and it excludes 2020 as there is no climate data available for the full year of 2020 yet.

Analysis parameter	Value	Notes
Timeframe for future scenarios	2021-2040 2041-2060	These timeframes are centered on the years 2030 and 2050, respectively. These timeframes align with the “near-term” and “mid-term” timeframes in the CEA Guide, respectively.
Spatial resolution	Ranges from 1km x 1km to 100km x 100km, depending on the climate variable	See Table 3.3 for the spatial resolutions of each climate variable
Temporal resolution	Ranges from daily to annually, depending on the climate variable.	Most variables are modeled with a monthly temporal resolution. See Table 3.3 for the temporal resolutions of each climate variable.
Key potential climate hazards included in analysis	Changes in mean annual and/or seasonal temperature Changes in runoff and ground conditions Changes in type, timing and intensity of precipitation Changes in water availability Changes to extent and duration of snow cover (e.g., timing of spring melt), permafrost melt and ice conditions (e.g., deepening of annual thaw) Drought and wildfire Duration of growing season Heat waves Ice storms and freezing rain Major precipitation events, overland flooding and storm surges Sea level rise Wind events	All but three climate hazards listed in Table 3.1 were included in this analysis. The three excluded hazards were: electrical storms; pathogens, pests and diseases; and shifts in species range or reproductive patterns for plants and animals. Reasons for exclusion are provided in Section 8.2 of the Manifest Technical Report.
Means and extremes	Considered the 5 th and 95 th percentile and the mean of climate model outputs	For the coastal and riverine flooding variables, mean, minimum, and maximum were used.
Future warming scenarios	RCP 4.5 and RCP 8.5	RCP 8.5 was selected to represent the “worst case” climate scenario, and RCP 4.5 represented the lowest global warming or “best case” climate scenario for which the most up-to-date data was available. An overview of scenario analysis is provided in Step 1 .

The parameters described in Table 3.2 laid the foundation for the climate data selection and analytics required for NS Power’s physical climate data analysis. The following data sourcing hierarchy was used to select the most suitable, reliable, and credible sources:

- Tier 1: Canadian publicly available, nationally recognized, peer-reviewed climate data sources; e.g., Canadian Centre for Climate Modelling and Analysis, Canadian Wildland Fire Information System.

- Tier 2: Internationally recognized, publicly available, peer-reviewed climate data sources, e.g., IPCC, CMIP5.¹⁸ The international data sources were used to supplement the Canadian sources and fill any data gaps, where necessary.

For each climate variable listed in Table 3.1, Acclimatise sourced datasets to provide present-day data as well as future 2030 and 2050 projections data. Multiple climate models were used for projections data. This number of models ensured adequate statistical and confidence interval analysis to account for climate modeling uncertainty. The following five types of datasets were used in this exercise (excerpt pulled from the Acclimatise Technical Report):

- 1) **Reanalysis:** Reanalysis is the closest dataset available to pure observed data on a global scale. It combines large volumes of observed data from weather stations and remote sensors with high-resolution numerical weather models.
- 2) **Statistically downscaled climate projections (SDCP):** Statistical downscaling makes use of statistical relationships between local observed climate variables and larger-scale climate patterns. The derived statistical relationships are applied to the large-scale projections data from General Circulation Models¹⁹ (GCMs) to infer local-scale projections at resolutions on the order of 1-10km.
- 3) **Dynamically downscaled climate projections (DDCP):** Dynamic downscaling uses the outputs of GCMs to drive a numerical Regional Climate Model (RCM) at a higher spatial resolution than GCMs. Typical spatial resolutions of RCMs range between 25 and 50km.
- 4) **Global climate projections (GCP):** Climate projections obtained from GCMs. GCMs are coupled atmospheric-oceanic models that account for a wide range of physical processes. Due to their global coverage, GCMs have coarser spatial resolutions than downscaled climate projections and are typically in the order of 100km resolution.
- 5) **Climate-related hazard datasets from other internationally recognized sources:** Climate-related hazards not present in reanalysis or climate projections. These include the landslide susceptibility provided by NASA's Landslide Hazard Assessment for Situational Awareness (LHASA) and the coastal and riverine flooding hazard datasets from the World Resource Institute (WRI).

Table 3.3 provides a summary of the climate data sources including the five types listed above used for each climate variable. The sources for the present-day dataset (see five types described above) are identified along with corresponding spatial and temporal resolutions, statistic outputs, and output units. Table 3.3 also provides data source and type of dataset for future projections.

The output from the physical climate risk analysis exercise was a substantial amount of climate data for each of the 100 critical assets including:

¹⁸ Coupled Model Intercomparison Project Phase 5 (CMIP5): CMIP is a standardized experimental framework for studying the results of coupled atmospheric-oceanic Global Climate Models. CMIP5 was the most current and up-to-date phase of the programme, with CMIP6 results issued by the IPCC in 2021.

¹⁹ Note that in common literature, "GCM" is also colloquially interpreted as "Global Climate Model", as such, becomes interchangeable with the more formal description of "General Circulation Model".

- Monthly output data for each of the three study timeframes – present-day (2010), 2030, and 2050 that:
 - Represented two warming scenarios, RCP 4.5 (best case) and RCP 8.5 (worst case) to capture a range of uncertainties and possible future outcomes provided in various statistical formats:
 - Typically including the mean, 5th, and 95th percentiles, in addition, other statistics were provided where identified/requested by NS Power, such as minimums and maximums (refer to Table 3.3 for details).

All of the climate data was provided to NS Power in GIS format so it could be input into its existing GIS framework and used for risk assessment by asset reliability teams.

Table 3.3: Summary of Present-Day and Future Projection Climate Data Sources, with Spatial & Temporal Resolutions where Available²⁰

Climate variable	Present-day dataset	Dataset type for present-day	Present-day spatial resolution	Temporal scale	Statistic	Output units	Future projections analysis data source(s)	Dataset type for projections analysis
Temperature, daily mean	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 95th, 5th	°C	CCCMA, ECCC, CMIP5	DDCP, SDCP, GCP
Temperature, daily max	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 95th	°C	CCCMA, ECCC, CMIP5	DDCP, SDCP, GCP
Temperature, daily min	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 5th	°C	CCCMA, ECCC, CMIP5	DDCP, SDCP, GCP
Total precipitation, daily	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 95th, 5th	mm	CCCMA, ECCC, CMIP5	DDCP, SDCP, GCP
Snowfall	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 95th, 5th	cm	CCCMA, CMIP5	DDCP, GCP
Precipitation type	ERA5	Reanalysis	30x30 km	Monthly	Mean, 95th, 5th	Dimensionless	CCCMA, CMIP5	DDCP, GCP
Surface pressure	ERA5-Land	Reanalysis	9x9 km	Monthly	Mean, 95th, 5th	Pa	CCCMA, CMIP5	DDCP, GCP
Specific humidity	ERA5	Reanalysis	30x30 km	Monthly	Mean, 95th, 5th	kg * kg-1	CCCMA, CMIP5	DDCP, GCP
Wind gust, daily	ERA5	Reanalysis	30x30 km	Monthly	Mean, 95th, 5th	m * s-1	CCCMA, CMIP5	DDCP, GCP
Wind gust, annual	ERA5	Reanalysis	30x30 km	Annual	n/a	m * s-1	CCCMA, CMIP5	DDCP, GCP
Sea surface temperature, daily mean	ERA5	Reanalysis	30x30 km	Monthly	Mean, 95th, 5th	°C	CMIP5	GCP
Sea level rise	CMIP5	Global Climate Projections	100x100 km	n/a (Annual)	Mean	m (relative to 1986-2005 baseline)	CMIP5	GCP

²⁰ Adapted from Table 1 and Table 2 from Acclimatise Technical Report

Climate variable	Present-day dataset	Dataset type for present-day	Present-day spatial resolution	Temporal scale	Statistic	Output units	Future projections analysis data source(s)	Dataset type for projections analysis
Coastal flooding	WRI Aqueduct	Climate hazard dataset	1x1 km	n/a (Annual)	Mean, max, min	m	WRI Aqueduct	Climate hazard dataset
Riverine flooding	WRI Aqueduct	Climate hazard dataset	1x1 km	n/a (Annual)	Mean, max, min	m	WRI Aqueduct	Climate hazard dataset
Landslide susceptibility (rainfall-induced)	LHASA NASA	Climate hazard dataset	1x1 km	n/a (Annual)	n/a	susceptibility: 0 - 4	NASA	Climate hazard dataset
Wildfires (Fire Weather Index (FWI))	ERA5	Reanalysis	30x30 km	Daily	Mean, 95th, 5 th	Dimensionless	CMIP5	GCM
Wildfires (historical)	FIRMS NASA		1x1 km	n/a (historical)	n/a	Dimensionless	n/a	n/a

ECCC: Environment and Climate Change Canada, Statistically downscaled climate projections

CCCMA: Canadian Centre for Climate Modelling and Analysis, Dynamically downscaled climate projections

CMIP5: Coupled Model Intercomparison Project Phase 5, Global climate projections

ERA5: European Centre for Medium-Range Weather Forecasts, Reanalysis

ERA5-Land: European Centre for Medium-Range Weather Forecasts, Reanalysis

WRI Aqueduct: World Resources Institute (WRI) Aqueduct Floods, Present day and projected global flood risk

NASA: Landslide Hazard Assessment for Situational Awareness (LHASA)

CWFIS: Canadian Wildland Fire Information System

3.2. Identification of Critical Assets and Operations Vulnerable to Climate-related Risks

Building on the criticality assessment of NS Power assets and the climate datasets, this section focuses on identifying assets and operations vulnerable to physical climate risks. To identify assets and operations vulnerable to physical climate risks, NS Power used the “List of potential climate impacts” table provided in Appendix 3 of the CEA Guide.²¹ The climate hazards (column 1) and corresponding potential climate impacts (column 2) were then mapped to each NS Power asset class/operation included in the exercise to build NS Power’s *Climate Master spreadsheet*. Each of the potential climate hazards (see box to the right), and the associated potential climate impacts, were evaluated for each asset class/operation.

Climate Hazards, Column 1, Appendix 3 in CEA Guide	
Changes in annual and/or seasonal patterns	
1	Changes in mean annual and/or seasonal temperature
2	Changes in water availability
3	Changes in type, timing and intensity of precipitation
4	Changes in runoff and ground conditions
5	Changes to extent and duration of snow cover (e.g. timing of spring melt), permafrost melt and ice conditions (e.g., deepening of annual
Increasing frequency, intensity and/or duration of extreme events	
6	Heat waves
7	Drought and wildfire
8	Wind events
9	Major precipitation events, overland flooding and storm surges
10	Ice storms and freezing rain
11	Electrical storms
Changes to ecosystem	
12	Shifts in species range or reproductive patterns for plants & animals
13	Pathogens, pests and diseases
14	Duration of growing season
15	Sea level rise

The NS Power-defined criteria used for evaluation included: adaptation degree, operational and capital expenditure levels, and adaption timing as further described below. NS Power’s Enterprise Asset Management (EAM) team completed this evaluation based on the climate datasets, as well as anecdotal and experiential on-the-ground learnings such as knowledge of weather incidents, recorded damage, past project execution costs and known impacts on assets and operations.

The **Adaptation Degree** variable uses three classifications:

- Incremental - Climate impact is managed within existing processes
- Tactical - Climate impact requires new processes
- Strategic - Climate impact requires a significant change in assets or new assets

The **Expenditure Level** variables describe the operating and/or capital costs associated with climate impacts

The **Adaptation Timing** variable describes “when” NS Power expects to experience climate impacts

- Near-term – less than 5 years
- Medium-term – 5 to 10 years
- Long-term – more than 10 years

The asset classes or operational areas evaluated includes transmission lines, distribution lines, substations, thermal generating stations, hydroelectric generating stations, and wind generating assets. Through this process NS Power has developed a deeper understanding of the vulnerabilities for these different operational areas. Key climate impacts include both acute events, such as extreme weather interacting with transmission and distribution infrastructure, and chronic impacts, such as long-term changes in temperature and precipitation patterns.

²¹ NS Power recognizes that the list of potential climate impacts in Appendix 3 of the CEA Guide is not exhaustive but considers its 81 broadly illustrative impacts an excellent starting point from which to build this adaptation planning exercise.

Figure 3.1 below illustrates how these various climate hazards, such as storm surges, sea level rise, extreme weather events, and increasing wildfire risks, affect critical operational areas like transmission and distribution, hydroelectric and wind operations, shoreline infrastructure, electricity demand, and fish habitat restoration. By identifying these vulnerabilities, NS Power prioritizes and integrates climate risk management into its asset reliability and operational strategies, ensuring the resilience and sustainability of its electricity system in the face of evolving climate challenges. Assessment of the level of criticality for each asset/operation in NS Power's system, and its associated climate vulnerability, is managed by the relevant asset reliability team(s).

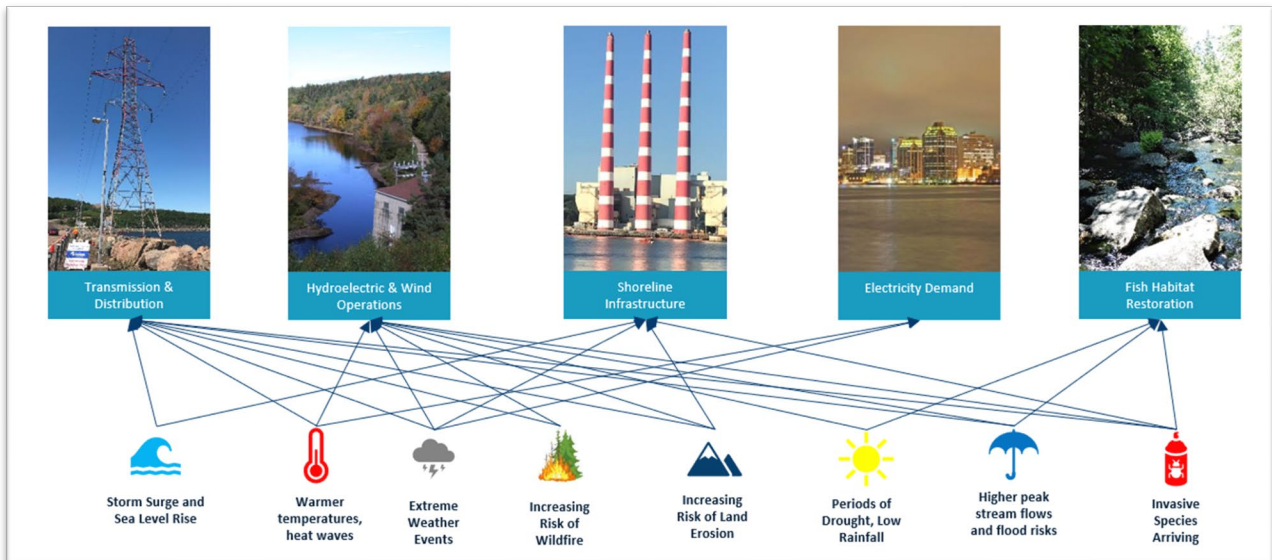


Figure 3.1 NS Power's Linking of Climate Impacts to Assets and Operations

To assist NS Power's EAM team with filtering through the extensive climate datasets generated, a prioritization tool called the Expenditure Level-Adaptation Degree (ELAD) Matrix was developed. The ELAD Matrix is designed to be used by asset reliability teams to incorporate climate hazards/impacts into the development of asset risk profiles and associated asset management plans. The matrix prioritizes climate hazards and the associated variables based on the effort (Adaptation Degree) and resources (Expenditure Level) needed to manage the climate impacts as shown in Table 3.4.

Table 3.4: Expenditure Level - Adaptation Degree (ELAD) Matrix Scoring

Expenditure Level	High	3	3	6	9
	Medium	2	2	4	6
	Low	1	1	2	3
			1	2	3
			Incremental	Tactical	Strategic
			Adaptation Degree		

ELAD Matrix scores are currently derived using data from the *Climate Master spreadsheet*, which is based on experiential and historical/observed information from NS Power's asset reliability teams. Once the climate datasets from the physical climate risk analysis are fully incorporated into NS Power's asset management mechanism, the data will be used to update the scores in the ELAD Matrix. This will ensure that the scores in the ELAD Matrix will be driven by quantitative climate data.

For a detailed explanation of the ELAD Matrix methodology, see Appendix F of Manifest Technical Report. For the full scoring of each climate impact for each asset class, see Appendix B of the Acclimatise Technical Report.

3.3. Selection of Key Climate Impacts for NS Power

The extensive climate dataset developed through the physical climate risk analysis completed by Acclimatise is being incorporated into NS Power's assessment of climate impacts for its assets and operations. This comprehensive dataset also serves as the foundation to inform NS Power's characterization of climate risks in [Step 4](#) of its adaptation planning process.

Table 3.5 below provides a summary of key potential climate impacts that may pose significant risks for NS Power in the delivery of its mission. This table will be refined in future iterations of this adaptation plan as per Step 4 of the CEA Guide. The table identifies the expected risk level for NS Power business unit(s) that would be primarily affected, provides brief descriptions of observed or anticipated impacts, and indicates whether the climate impact would be direct or indirect.²²

Table 3.5: Relevant Climate Hazards and Associated Climate Impacts for NS Power

Climate hazard	Expected risk level (high, medium, low)	Primarily affected business unit(s)	Impact description	Direct or indirect impact
Wind Events	High	Linear assets	Uprooted trees can damage T&D infrastructure	Direct
	High	Operations & maintenance	Uprooted trees can block access routes for maintenance crews	Indirect
	Medium	Operations & maintenance	Extreme winds can disrupt the vegetation management team	Indirect
Ice Storms and Freezing Rain	High	Linear assets	Ice accretion on trees and/or tree branches increases their likelihood of breaking or being blown over and damaging T&D infrastructure	Indirect
	High	Linear assets	Ice accretion on T&D lines adds additional physical load, putting them under greater physical stress. This increases the likelihood of breakage	Direct
Major precipitation	High	Point assets	Major precipitation events, overland flooding, and storm surges threaten coastal and low-lying	Direct

²² Direct impacts are defined by the CEA as those with "direct, i.e., unmediated, effects on assets and operations." Indirect impacts are defined as those that "initiate a chain of events that ultimately impact on assets and operations." Climate impacts can have direct, indirect, or a combination of both direct and indirect impacts on assets and operations.

Climate hazard	Expected risk level (high, medium, low)	Primarily affected business unit(s)	Impact description	Direct or indirect impact
events, Overland Flooding and Storm Surge			assets. This is especially relevant for the NS Power head office in Halifax, Tufts Cove Generating Station, and various hydro stations.	
Sea level rise	Medium	Linear assets	Rising sea levels can render coastal transmission and distribution infrastructure inaccessible due to flooded and/or damaged coastal maintenance roads. The foundations of poles can also be weakened by flooding, posing a physical risk to coastal electrical lines.	Direct
Changes in runoff and ground conditions	High	Operations & maintenance	Frequent and/or heavy precipitation renders marshland untraversable, blocking maintenance crew access to certain areas. This is especially relevant for the transmission corridor connecting NS Power to New Brunswick	Indirect
Changes in mean annual and/or seasonal temperature	Medium	Linear assets	An increased number of freeze-thaw cycles ²³ puts T&D lines under greater stress	Direct
Drought and Wildfire	Low	Linear assets, point assets, operations & maintenance	While much of the less densely populated regions of Nova Scotia are heavily forested, and NS Power's infrastructure in these regions is largely wooden, wildfires have not historically been a concern for Atlantic provinces.	Direct
Changes in mean annual and/or seasonal temperature	Low	Linear assets	Significant temperature increases could cause T&D lines to sag, potentially putting them in violation of mandated minimum height requirements. Elevated temperatures also reduce the efficiency of T&D lines.	Direct
	Medium	Substations & Thermal stations	Significant temperature increases could cause significant decreases in component efficiencies/performance. More frequent component maintenance and/or replacement could be expected as well.	Direct

It is also important to consider potential combined climate impacts that could elevate physical risks to NS Power's assets and operations. For example, in the wintertime, ice accretion and wind events may form a combined impact. Trees and branches loaded with ice are more susceptible to breakage during wind events, threatening damage to transmission and distribution assets.

²³ Freeze-thaw cycles depict how often the temperature fluctuates between above and below freezing.

3.4. Sample Climate Impact Assessment for Two Assets Critical to NS Power's Mission

Tufts Cove – Example of Key Climate Impacts of critical generation and substation asset identified in Step 2

Tufts Cove is a large, dual fuel generating station and is NS Power's main natural gas-fired asset, providing fuel-flexibility and reliability to the electricity system.

NS Power-known climate risks: Sea level rise and storm surge are physical climate hazards for Tufts Cove because it is located on the coast. Changes in mean annual and/or seasonal temperatures are also priority climate hazards because the performance of generation and substation equipment can be significantly affected by temperature swings.

Physical climate risk analysis preliminary learnings: Data from the risk analysis indicated that the month of August is projected to have the largest increases in number of hot days. From a present-day value of 3.7 days the total number of hot days rises to ~9 by 2030 for both RCP scenarios and ~11 and ~13.5 by 2050 for RCP 4.5 and 8.5 respectively. There is also a reduction in number of days below -5°C projected, with larger reductions observed by 2050 than by 2030 and more for RCP 8.5 than for RCP 4.5.

Finally, the projections indicate that sea level is expected to rise from present-day by a further 13cm and 16cm by 2030 for RCP 4.5 and 8.5 respectively. This worsens by 2050, with sea level rise from present-day of 20cm and 26cm, under RCP 4.5 and 8.5 respectively. The overall coastal flooding risk under a 2100-time horizon is depicted in Figure 3.2 below.



Figure 3.2 Example of Tufts Cove flood mapping showing 1% annual exceedance probability and 2100-time horizon

Nova Scotia-New Brunswick Transmission Corridor – Example of Key Climate Impacts for Critical Transmission Asset Identified in Step 2

The three transmission lines (one 345kV and two 138kV) connecting Nova Scotia and New Brunswick are critical to maintaining NS Power's system reliability.

NS Power-known climate risks: Flooding in this region has already been limited access for maintenance crews to transmission infrastructure. This region is bordered by the Bay of Fundy to the southwest and the Northumberland Strait to the northeast, so coastal flooding is a high priority climate hazard for this asset. In addition, ice accumulation and elevated temperatures can significantly affect the efficiency of transmission and distribution lines, as well as the physical integrity of the assets.

Physical climate risk analysis learnings: Data from the risk analysis indicated that projections of coastal flood depth increases between 2030 and 2050. The increase could be as low as 1.5m in 2030 under RCP 4.5 with a 2-year return period to almost 3m in 2050 under RCP 8.5 with a 1000-year return period. The percentage of liquid precipitation over total precipitation is projected to increase for the months of December and January in 2030 by ~1.3% and ~3.4% respectively for RCP 4.5 and by ~4% and ~2% respectively for RCP 8.5. As we move towards the 2050s or 2080s the number of freezing days will be fewer, suggesting that the probability of freezing rain will eventually decrease. In addition, projections indicate August will experience the largest increases in number of hot days, with the total number of days rising to ~3.5 and ~3 by 2030 for RCP 4.5 and 8.5 respectively, and ~4 and ~ by 2050 for RCP 4.5 and 8.5 respectively. Increased hot days can cause transmission lines to sag, reduce their efficiency, and accelerate the aging of critical components, thereby impacting overall system reliability.

Adaptations: NS Power recognizes the importance of protecting critical infrastructure, such as the Chignecto Isthmus, which is vital for maintaining reliable connections between Nova Scotia and the rest of Canada. The recent \$650 million funding agreement between Ottawa, New Brunswick, and Nova Scotia to reinforce the isthmus also reduces the risk to the critical transmission lines that run through this corridor, ensuring the continued reliability of power supply between NS and NB

The new NS-NB Reliability Tie was designed with climate change considerations, incorporating updated standards for overhead lines and enhanced foundations that reduce risks associated with extreme weather events and flooding. These measures enhance the resilience of the infrastructure, ensuring it can withstand the increasing frequency and severity of climate-related impacts.

4. Step 4: Assess Risks to Critical and Vulnerable Assets and Operations

This section explains NS Power's existing asset risk assessment process and lays the groundwork for integrating climate impacts into assessments of generation and T&D assets. Details are given on how assets are assessed for risk, including the general scoring methodology. The resulting risk profile is utilized for risk mitigation planning, which will include adapting to climate considerations.

NS Power's EAM team uses an enterprise-wide asset risk assessment process (the asset management mechanism) to evaluate risk for its physical assets. The objective of Step 4 in the CEA Guide is to assess the risk that existing and potential climate impacts pose to assets and operations critical to the successful delivery of NS Power's mission. This section describes the *asset management risk assessment process* that NS Power's asset reliability teams use to inform the operation, investment plans, and maintenance strategies for its assets. This process will be used to incorporate climate risks alongside other risks, such as safety, and to identify the need for climate change adaptation for assets most at risk to climate impacts.

4.1. NS Power's Asset Risk Management Process – Asset Reliability Teams

The Asset Reliability Team process at NS Power, as detailed in the Asset Management System Procedure (NSPI-AMS-001), plays a crucial role in the Company's climate adaptation strategy. This process involves dedicated teams of engineers, scientists, and technicians who are subject matter experts in various asset types. These teams are responsible for assessing and managing asset risk, developing maintenance strategies, and updating asset-level risk profiles. By leveraging a comprehensive risk matrix, the asset reliability teams evaluate the condition and criticality of assets to determine their risk levels and identify appropriate mitigation measures. This systematic approach to risk management ensures that NS Power's assets are resilient and capable of withstanding climate-related impacts. Integrating the Climate Adaptation Plan into the existing, robust asset reliability team process allows NS Power to proactively address emerging risks, optimize maintenance strategies, and enhance the overall reliability and resilience of the power system.

Critical NS Power assets have one or multiple asset reliability teams whose mandate is, in part, to assess and manage asset risk, sometimes at the system level, e.g., *substation*, but most often at an asset level, e.g., power transformer (herein referred to as "assets" for simplicity). Asset reliability teams at the time of writing are as follows:

- | | | |
|---------------------|---------------------|------------------|
| 1) Air Quality | 9) Heat | 14) Turbines & |
| 2) Boiler | Exchangers | Generators |
| 3) Chemical | 10) Hydro | 15) Substations |
| 4) Civil Structures | Mechanical | 16) Telecom |
| 5) Combustion | 11) Instrumentation | 17) Transmission |
| Turbines | & Controls | 18) Vegetation |
| 6) Dam Structures | 12) Ash Residue | 19) Wind |
| 7) Distribution | 13) Rotating | |
| 8) Electrical | Equipment | |

Some asset reliability teams feed information into other asset reliability teams, for example the *distribution* and *transmission* asset reliability teams feed information into the *vegetation* team. Facilities that have multiple asset reliability teams associated with them, such as Wreck Cove Hydroelectric Station, will have a “stacked” risk profile. This means that the risk assessment outputs from all associated asset reliability teams can be combined, or stacked, to produce one risk profile for the facility.

Wreck Cove Reliability Teams:

- Civil structures
- Dam structures
- Hydro mechanical
- Electrical
- Instrumentation & controls

4.2. NS Power’s Asset Risk Assessment Process – Risk Profiles

In the assessment of risk, NS Power considers three main aspects for each asset: its mission and utilization, its criticality to the electrical system, and its condition or likelihood of failure. Asset reliability teams develop a risk profile for each asset based on these aspects, as described in the Asset Management Plans (AMPs). The mission of an asset is derived from its function within NS Power’s operational systems and the utilization factor, which is a forward-looking indication of the asset’s future operating requirements. This factor is determined through iterative system planning processes (such as the Integrated Resource Plan or IRP), and considers inputs such as historic reliability, condition, age, maintenance and operating costs, and operational restrictions. Depending on the projected risk based on potential climate impacts, an asset life assessment may be conducted to determine if the mission of the asset needs to be changed.

To assess criticality, potential impacts related to health and safety, environment, brand/customer impact, and financial considerations from the failure of the asset are considered. Typically, the criticality of an asset is determined once and reassessed if major system changes occur. The condition assessment, completed annually by asset reliability teams, evaluates the likelihood of asset failure or inability to meet operating expectations. This assessment considers inputs from preventative maintenance activities, advanced pattern recognition, condition-based monitoring, surveillance, and health assessments and lived field-level experience. The risk profile for an asset is the product of the criticality and condition assessments. Figure 4.1 provides a visual overview of NS Power’s asset risk assessment process, known as the asset management mechanism. For more detailed information, refer to the Capital Expenditure Justification Criteria (CEJC) and Criticality Assessment SOP (NSPI-AMS-002).

The risk profile is developed by the asset reliability team and then used to create the asset risk mitigation strategy based on the asset’s mission. The asset-specific risk mitigation plan is refreshed regularly, often annually, and is part of the asset’s management plan. It is also used as an input to the capital planning and resourcing processes as further described in the SAMP.

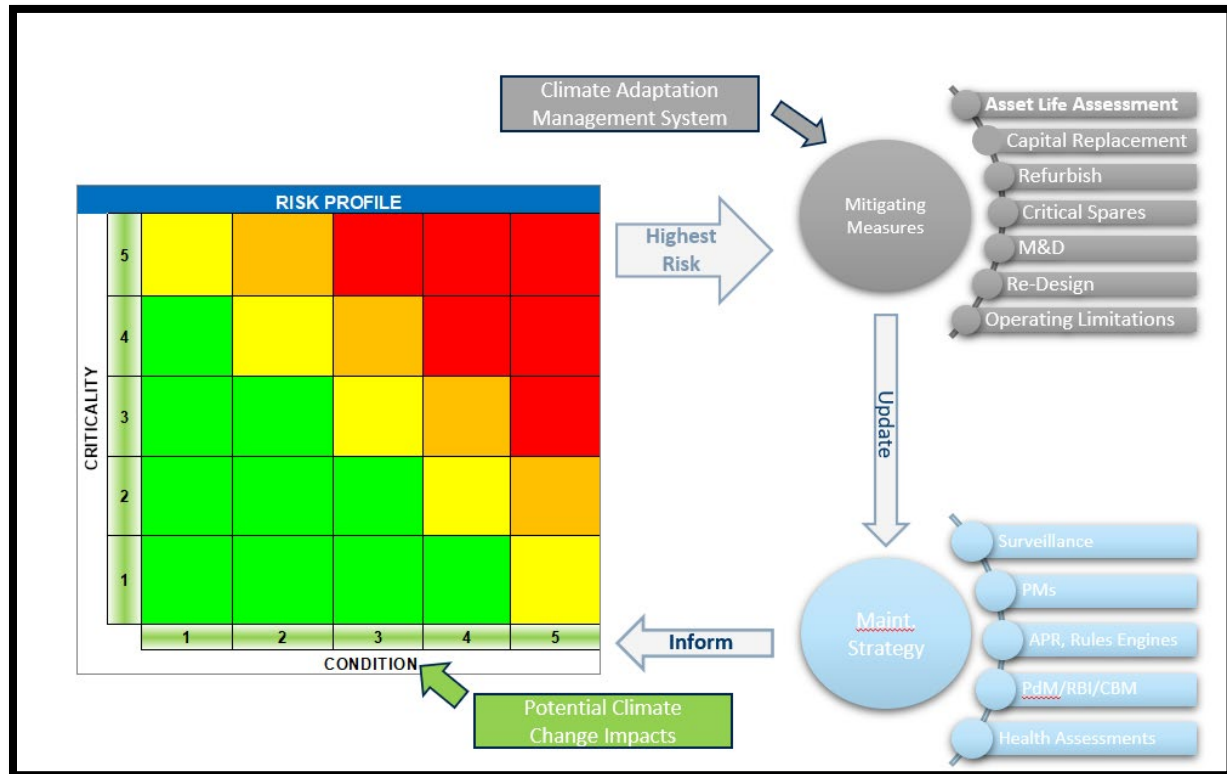


Figure 4.1: Overview of NS Power's Asset Management Mechanism

Evaluating Climate Datasets for Physical Impacts to Assets

NS Power regularly reviews the climate datasets provided by Acclimatise and Manifest in [Step 3](#) to integrate the key climate impacts (Table 3.5) into the risk assessment process as described above. And where applicable site-specific climate reviews will be conducted to review site or asset specific risks.

For example, wind events have been identified as a key climate impact for NS Power's overhead linear assets. This would prompt the transmission and distribution asset reliability teams to review available wind data. The 1:50 and 1:150 return period values for wind from available historical data were estimated to be lower than CSA-recommended return period values, and so the wind values from CSA 22.3 No. 60826-19 were recommended for load design. Climate data provided in [Step 3](#) indicates an increasing trend in maximum wind speeds, which may further increase in 2030 and 2050 under different future climate scenarios. Access to, and understanding of, this climate data assists asset reliability teams in assessing risks to transmission and distribution assets, such as falling trees during high wind days. This knowledge ensures that risk mitigation plan development is informed by, and perhaps driven by, climate risk. Refer to Figure 4.2 for an output climate input updated as part of this study.

Climate Parameter	ERA5 Grid Location	Trend	Historical 1:50 Return Period Value	Adjustment for Climate Change Projection		
				2030s	2050s	2070s
Ice Thickness ¹	1	Decreasing	31 mm	-	-	-
	2		36 mm			
	3		34 mm			
	4		36 mm			
	7		36 mm			
	8		36 mm			
Wind Speed	1	Increasing	104 km/hr	105 km/hr	107 km/hr	106 km/hr
	2		106 km/hr	107 km/hr	108 km/hr	109 km/hr
	3		106 km/hr	107 km/hr	108 km/hr	109 km/hr
	4		106 km/hr	107 km/hr	108 km/hr	109 km/hr
	7		104 km/hr	105 km/hr	107 km/hr	106 km/hr
	8		104 km/hr	105 km/hr	107 km/hr	106 km/hr

¹Ice thickness was projected to decrease in the future so no climate adjustment is recommended.

Figure 4.2: NS Power data from Climate Study for Ice Thickness and Wind Gusts in NS.

As another example, climate data on flooding and sea level rise are reviewed by the substation asset reliability team transformers and other major substation assets near the coast and rivers. Understanding trends for related climate variables helps engineers determine if particular transformers need to be flagged as having a high probability of failure due to flooding. A high probability could result in a high-risk score for those assets and lead to consideration of design changes, relocation, or other flood protection activities as mitigating measures.

Chapter 3: Risk/Opportunity Response and Adaptation Planning

Chapter 3 comprises two steps that show how NS Power's asset risk assessment approach can be used to record and monitor climate data and feed learnings from the data into decisions on mitigating measures. This will enable NS Power to identify, rank and prioritize selected adaptation measures with an enterprise-wide perspective. The two steps are [Identify Potential Adaptation Measures](#) and [Develop a Business Case for Selected Measures](#).

5. Step 5 Identify Potential Adaptation Measures (risk controls)

This step reviews the types of risk mitigation measures that are available to NS Power to adapt to physical climate impacts and the Company's management system for climate information.

*"The overarching objective of adaptation planning is [building] resilience to risk."*²⁴ As part of the annual risk assessment process completed by asset reliability teams across NS Power, all risks evaluated as "high" must be mitigated and risks ranked "medium-high" must be considered for the implementation of risk mitigation measures, as informed by the asset's mission. The results of the risk assessment (i.e., the resultant "block" in the risk matrix included in Figure 4.1) are considered a guidepost and are used to filter risks to those that require additional scrutiny by subject matter experts. There is no set response or mitigation plan associated with any given result, and two assets which were evaluated in the same block do not necessarily receive the same treatment. A risk may be accepted, mitigated or managed, regardless of its evaluated risk rating.

As shown in Figure 5.1, risk mitigation options are brought forward in two main streams. The first is through asset reliability teams who bring forward high-risk assets identified with possible mitigation options. In the second stream, capital engineering resources from Operations will communicate an asset requiring mitigation. The EAM team will then assess and prioritize all potential mitigation requirements that have been brought forward for capital investment and may identify alternate (non-capital) forms of mitigation for some assets.

²⁴ CEA Guide

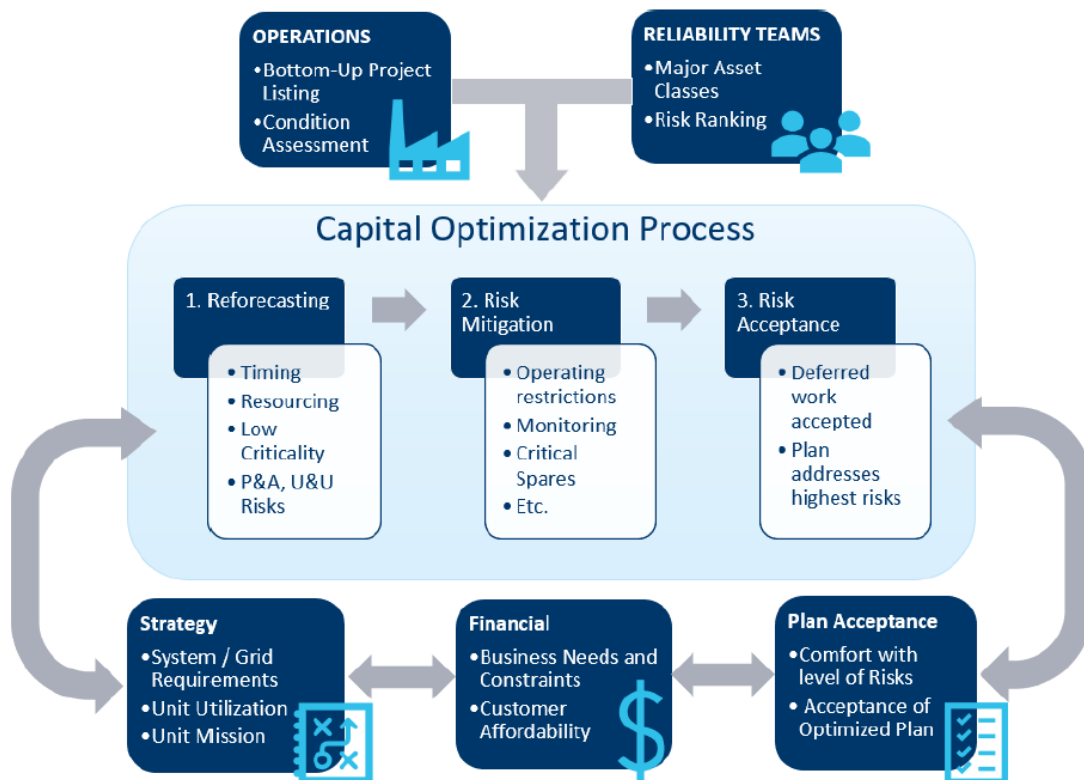


Figure 5.1: NS Power Capital Planning Cycle

As described in [Step 4](#), climate risks are assessed with all other potential risks through NS Power's asset risk assessment process. The risk mitigation measures used by NS Power to address all forms of risk, including climate, broadly fall within the categories circled in Figure 5.2 and described in detail below as part of the risk mitigation mechanism. These include:

- Critical Spares;
- Monitoring & Diagnostics;
- Re-design;
- Operating Limitations;
- Refurbishment;
- Capital Replacement; and
- Asset Life Assessment.

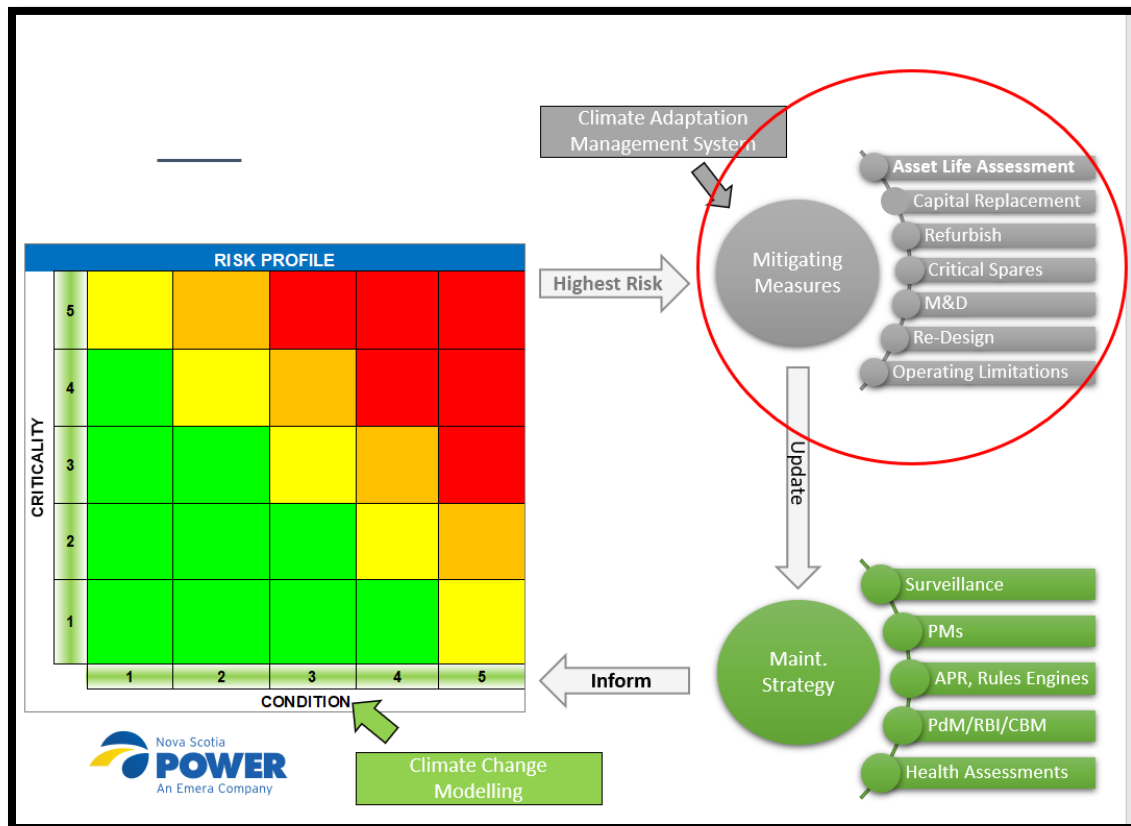


Figure 5.2: Risk Mitigation Options for High Risk Assets

5.1. Overview of Risk Mitigation Option Categories

Critical Spares

The critical spares option is used to prepare for the failure of the asset. The critical spare would be kept in inventory, or readily available from approved suppliers, to enable a relatively quick replacement and return-to-service of that failed asset or component, thereby limiting the impact to operations and/or customers. A critical spare may be suitable where the asset is complex with many components, where an asset or a component has significant lead time, or where an inexpensive though critical item can be kept on the shelf for minimal investment. A spare may fall within operating or capital expenditures depending on type of component/asset (i.e., is it consumable) and associated expenditure level. For example, an electrical storm may impact a pole-top transformer. Spares of pole-top transformers can be kept in inventory as they are relatively inexpensive and can be quickly installed following a failure of this kind.

Monitoring & Diagnostics (M&D)

Monitoring and diagnostics is chosen for equipment that can be regularly or continuously monitored and for equipment that can have testing completed or diagnostics deployed to provide advanced information about the initiation or imminent failure. When this form of risk mitigation is selected for a high risk asset, it typically involves the introduction of a new form of monitoring or diagnostics or an increase in the frequency of existing forms of monitoring and/or diagnostics.

This option may be suitable where an item has parameters that can be readily measured, such as vibration or temperature, or where operational tests are effective in identifying the onset of failure mechanisms of concern. This measure may be implemented through operating or capital expenditures, depending on if new assets (monitoring devices for example) are required. For example, monitoring devices can be installed to assess the level of ice build-up on high-risk transmission lines.

Re-design

Re-design typically requires engineering input to modify/redevelop an asset to incorporate changes to reduce the risk of failure. In some cases, it may involve changing the design standard to ensure new assets of a particular type meet the re-designed specifications. Re-design is suitable when the current design is inadequate to achieve its mission into the future, and when alterations may provide improved performance or capacity. Re-design may be capital or operating expenditure depending on the magnitude and type of work completed. For example, to address the risk of galloping lines associated with wind events such as hurricanes, which may lead to failure, conductor sizing can be increased and/or the fasteners that attach the conductor to the poles can be re-designed.

Operating Limitations

There are many ways that managing the operation of a particular asset, or group of assets, in a new way, or modifying operating limitations on the asset, can be an effective form of risk mitigation. This measure is often implemented through updates to operating procedures, operational advisories, and/or competency-based training programs. Operating limitations are suitable where a failure mechanism is exacerbated through operation at certain levels, or through on/off cycles, etc. Limitations can be put into place to ensure the asset is not operated in a manner which accelerates the issue of concern. As an example, a dam structure may have been built to the design standards of the day 40 years ago, but when reviewing a dam asset to today's standards, a structure may not be of sufficient height to meet the freeboard capacity required when operating at full supply level for a storage reservoir. An operating limitation would be to reduce the maximum storage level of the reservoir to a lower level, thereby creating more freeboard capacity for the dam. Typically, this option would fall within operating expenditures but could be a capital expenditure if investment is required to ensure the asset is properly operated within the new limitations.

Refurbishment

For many assets, it is possible to refurbish to extend the useful life and/or increase the functional operation of the asset rather than completely replacing the asset. Refurbishment may entail significant component replacement, machining, or other physical modifications to an asset and may be suitable where full replacement is very costly and time-consuming. Refurbishment also allows introduction of upgraded components if design standards have changed, or where there have been changes to operating conditions (i.e., metallurgical change to respond to change in chemistry of cooling water). For example, a cooling water pump which has been damaged through biological growth may be disassembled, re-machined and components replaced to return it to good working order. Refurbishment may be considered under operating or capital expenditures depending on whether the refurbishment meets capitalization criteria for magnitude as well as benefit (extended life, increased capacity, etc.).

Capital Replacements

Capital replacement, in essence replacing the entire asset with a new asset, is often one of the last options selected for risk mitigation as it is often the costliest. The new asset may be of similar specifications to the asset being replaced or it could be based on newer standards, incorporating recent technological advancements or other changes to support addressing the risk(s) identified in the existing asset. Replacement may be a viable option if the asset cannot be refurbished or if risks cannot be managed adequately through other methods. Replacement may also be selected if it is more cost-effective than refurbishment in serving the asset's mission (i.e., replacement may provide significantly greater life than refurbishment, for minimal extra cost). Typically, an economic analysis is performed in those cases. An example of this would be replacing a low-lying substation with a new substation at a higher elevation to mitigate a high risk for inundation during major precipitation events.

Asset Life Assessment

An asset life assessment may be considered if drivers such as financial or regulatory requirements, or as described herein, significant anticipated climate impacts, do not support the other forms of risk mitigation even if they might be technically viable. This option considers the desired asset mission, or the expected lifecycle for the asset, along with risks that may significantly challenge the Company's ability to execute on that mission due to constraints. The outcome from an asset life assessment could be a refurbishment, capital replacement or asset retiring/decommissioning. In the case of an asset retirement or decommissioning, the timeline may not be immediate. Other forms of risk mitigation or management may be implemented while the future retirement date is determined, and general investment into that asset would be minimized. For example, if sea level rise is impacting a fixed generation asset located on the coast at sea level, the only viable long-term option may be to consider the timing and planning to decommission the site. Such an assessment is most often undertaken within operating budgets.

5.2. Five-Year Reliability Plan

The Five-Year Reliability Plan, filed with the Nova Scotia Utility and Review Board in December 2024, represents a significant investment of \$1.3 billion aimed at enhancing the resilience and reliability of NS Power's grid. This plan is intricately linked to the Climate Adaptation Plan, ensuring that NS Power's infrastructure is prepared to withstand the increasing frequency and severity of climate-related events. By leveraging the Climate Adaptation Plan and processes described herein, the Reliability Plan focuses on three core programs: Storm Hardening - Vegetation Management, Storm Hardening - Targeted Equipment Replacements and Upgrades, and Advanced Grid Modernization.

Through these targeted investments, NS Power aims to reduce the duration and frequency of outages, while also improving grid resilience to meet performance standards for restoring service within 48 hours after major events. The Storm Hardening programs will manage vegetation around power lines and upgrade critical equipment to withstand extreme weather conditions, thereby reducing the risk of outages. Advanced Grid Modernization will implement cutting-edge technologies to create a more adaptive and resilient grid, capable of responding to evolving demands and integrating renewable energy sources.

By aligning reliability investments with climate adaptation strategies, NS Power is committed to building a power system that not only meets current reliability standards but is also equipped to

handle future climate challenges. This integrated approach ensures that NS Power's customers receive dependable and efficient power service, even in the face of severe weather events.

5.3. Wildfire Mitigation Plan

As part of NS Power's comprehensive climate adaptation plan, the Wildfire Mitigation Plan plays a crucial role in enhancing the resilience of the Company's electrical infrastructure against the increasing threat of wildfires. The Wildfire Mitigation Plan, updated in 2025, outlines key initiatives such as vegetation management, equipment upgrades, and operational changes designed to prevent wildfires, minimize potential damage, and ensure the reliability of electricity services. By integrating advanced technologies like real-time monitoring systems and predictive analytics, the plan aims to proactively manage wildfire risks and protect public safety. This approach not only addresses immediate wildfire threats but also aligns with NS Power's long-term vision of creating a sustainable and resilient electrical grid capable of adapting to evolving climate conditions.

6. Step 6: Develop a Business Case for Selected Measures

This section overviews the procedure for prioritizing recommended adaptation measures. NS Power has robust existing operating and capital expenditure budgeting processes. Adaptation to climate change risks can be seamlessly integrated into these processes.

From [Step 5](#), NS Power will have a series of high-risk assets and identified mitigation options to address climate physical impacts. The selection of a particular risk management measure is dependent on cost and ease of implementation, likelihood of success in mitigating the risk, the expected benefit of the mitigating measure, as well as the asset mission and other inputs. NS Power strives to minimize costs for customers and maximize the operating capacity and life of its assets. Where there are multiple viable options, an economic analysis may be performed. In some cases, multiple types of risk mitigation are implemented on a single asset to better manage the risk. Risk management plans are proposed through collaboration by the multi-disciplinary asset reliability teams, receive management approval, regulatory approval as required, and are implemented by the responsible business unit. Refer to Figure 5.1.

The various forms of risk mitigation described in [Step 5](#) may be covered either operating expenditures or capital expenditures. Mitigating measures funded through operating budgets would be covered within existing operating budgets parameters managed by the business unit responsible for the asset. Capital risk mitigation options would fall within the NS Power Capital Expenditure Justification Criteria (CEJC) processes. The detailed documents for the CEJC process are covered within the *Nova Scotia Power Inc. Capital Planning & Capital Expenditure Justification Criteria Summary Document (July 31, 2023²⁵)*. Processes for evaluating and prioritizing suggested capital expenditures based on quantitative and qualitative cost and benefit data are described in the CEJC.

At the center of the CEJC process is NS Power's risk matrix deployed by the EAM team to assess risk and prioritize items being submitted for capital expenditures. See Figure 6.1 showing the risk matrix contained within the CEJC summary document. This is the same 5x5 risk matrix outlined within [Step 4](#) of this adaptation planning document. Therefore, incorporating climate impacts into our existing risk ranking processes allows NS Power to utilize the longstanding process within the CEJC.

²⁵ This document is managed by the NS Power Regulatory Affairs team and is periodically submitted to the Nova Scotia Utility and Review Board for approval.



Figure 6.1: Risk Matrix from the NS Power CEJC Summary Document

Where a recommendation requires economic analysis for justification (i.e., more than one viable option exists), an Economic Analysis Model (EAM) is completed. The EAM template is approved by the Nova Scotia Energy Board through the CEJC approval process, and has consideration for payback period, likelihood of failure, anticipated future investments, time-value of money, interest costs, etc.

Chapter 4 Preparation for Implementation

Chapter 4 comprises two steps on forward-looking implementation. Although NS Power is well-prepared with a robust, existing asset risk management system, integrating climate data and long-term scenario learnings associated with climate change will require practice. These steps outline climate-related actions associated with different roles in NS Power and the monitoring and reporting to drive implementation and improvement.

7. Step 7: Detail and Document Implementing Control Actions

This section lists the various NS Power roles that will be involved in integrating climate considerations in order to fulfil this adaptation plan. Each role will have a list of specific actions that fall under its purview. Responsibility for various steps in this adaptation plan is spread from the leadership team to individual risk assessment personnel.

The objective of Step 7 in the CEA Guide is to determine the governance needed to support the climate analysis and adaptation plan. As discussed in the previous sections, NS Power fully integrates the consideration of key climate impacts into the existing risk management processes deployed as part of the enterprise asset management system. The governance of the asset management system supports the various roles to ensure they have the right information to identify and assess climate-related adaptation needs and so that asset management processes can accommodate the adaptation measures.

7.1. Roles & Responsibilities

The governance of the Climate Adaptation Plan and the associated process will be managed within the following organization structure, utilizing existing resources. Effective implementation of the Climate Adaptation Plan depends on employees across many departments taking responsibility for various tasks. Specific accountabilities are covered in the roles and responsibilities for various key departments and positions shown in Figure 7.1 and as listed below.

NS Power Executive Leadership Team

- Ensures the Climate Adaptation Plan is compatible with the strategic direction of the organization;
- Provides visible leadership and strategic direction for the climate adaptation planning and programs in their area of responsibility;
- Periodically reviews climate adaptation programs and performance for appropriateness and fit with the company's needs; and
- Holds senior leaders accountable for implementation of the Climate Adaptation Plan and the effectiveness of the underlying risk management system as described in this manual.



Figure 7.1: Organizational Chart for Management & Oversight of Climate Adaptation Plan

Senior Directors (Asset Management and Environment)

- Provide visible leadership and strategic direction for the climate adaptation planning and programs;
- Ensure the Climate Adaptation Plan achieves its intended outcomes related to improving organizational resiliency to the physical impacts of climate change, prioritization of climate-related risks, and leveraging new business opportunities and innovation to adapt to climate change;
- Allocate adequate resources to enable implementation of climate adaptation planning programs consistent with corporate and business unit policies and standards; and
- Hold leaders accountable for the implementation of the climate adaptation planning programs and resulting performance.

Enterprise Asset Management (Managers)

- Is directly accountable for performance against key metrics for climate impacts (see Section 8.2);
- Allocates resources to enable implementation of Climate Adaptation Plan;
- Participates actively in the risk assessment of key climate impacts and as required, capital planning to mitigate risks; and
- Raises climate change issues or concerns to senior leaders where warranted.

Climate Adaptation Risk Lead

- Manages climate datasets;
- Integrates knowledge of key climate impacts and climate datasets into asset reliability team risk assessments;
- Reviews climate-related asset risk scores from asset reliability teams;
- Maintains the content of the Climate Adaptation Management System (CAMS); and
- Monitors climate-related performance metrics;
- Obtains updated climate datasets on a periodic basis; and
- Maintains and updates the Climate Adaptation Plan document.

Asset Reliability Team Leads/Members

- Become familiar with the key climate risks and associated impacts relevant to the particular asset class and, review available climate datasets relevant to those key climate risks and impacts;
- Factor the climate datasets and potential for climate impacts into the overall risk assessment of assets relevant to the asset reliability team;
- Include considerations for climate risks in asset management plans;
- Maintain understanding of technological innovations that could be deployed to address climate impacts; and
- Proactively identify opportunities to improve climate adaptation programs and performance and share them with responsible asset management representatives.

NS Power's Asset Management System includes multiple internal tracking and reporting mechanisms that inform the roles described above about the decisions made and asset strategies implemented. The metrics reported through these communication pathways both measure the effectiveness of asset mitigation plans, including climate-related adaptation as well as drive continuous improvement as described in [Step 8](#).

8. Step 8: Establish a Process to Review and Improve Plan

Monitoring implementation and reviewing progress is an essential step to drive improvement. This section outlines metrics, reporting, review, and future steps to ensure NS Power has the best available climate information.

The objective of Step 8 in the CEA Guide is to establish a process that will be used to monitor the adaptation plan. Monitoring provides a two-fold purpose: first, assessing the plan's suitability, adequacy, and effectiveness; and second, presenting implementing actions to ensure continual improvement of the plan. NS Power has several reporting pathways that support both objectives. These include performance metrics for T&D assets and power generation assets, review of the asset reliability teams themselves, as well as ongoing and ad hoc event analysis. These are detailed below.

8.1. Performance Metrics & Reporting

System reliability and availability is currently monitored and reported on monthly basis by Enterprise Asset Management for both the T&D division as well as the Generation division. These reports summarize the overall reliability of the assets across NS Power and highlight the various risk conditions across the business. It also provides a source of data to validate the effectiveness of the risk mitigation choices being deployed, or to highlight where additional risk mitigation is required. Although these reports are not specifically targeted to climate-related impacts, the information can be filtered through the climate adaptation lens, providing insight into the effectiveness of the Climate Adaptation Plan.

For T&D, this report is called the *System Reliability Performance Update* and includes the following reliability statistics shown in Figure 8.1, such as SAIFI²⁶ and SAIDI²⁷ which are a representative of the average number and duration of customer interruptions, respectively. This information is also calculated at the feeder level, allowing T&D performance engineers to highlight potential problem feeders that experience the largest number of customer interruptions and/or customer hour interruptions. The enhanced knowledge on climate change physical risks gathered in Steps 2 through 4 coupled with the analytics in the system reliability updates will allow NS Power to identify and prioritize climate adaptation measures.

²⁶ System Average Interruption Frequency Index

²⁷ System Average Interruption Duration Index

2024 Reliability Update Summary				
	YTD	Target	Status	Trend
BSC Target				
Blue Sky CAIDI (EED, MED, SED removed)	2.09	<1.82	✗	Exceeded
Storm CAIDI (EED, MED, SED)	4.75	<9.82	✓	Achieved
BSC Stretch				
Blue Sky SAIDI (EED, MED, SED removed)	5.29	<3.75	✗	Exceeded
Storm CAIDI (EED, MED, SED)	4.75	<9.31	✓	Achieved
Performance Standards				
SAIFI	1.97	< 2.05	✓	Achieved
SAIDI	5.26	< 4.29	✗	Exceeded
Problem Feeders Frequency (CKAIFI)				
57S-401	95.7%	< 95%	✗	Exceeded
85S-401	88.1%	< 95%	✓	Achieved
Problem Feeders Duration (CKAIDI)				
91W-411	98.9%	< 95%	✗	Exceeded
57S-401	90.4%	< 95%	✓	Achieved
1W-411	89.6%	< 95%	✓	Achieved
4N-313	80.4%	< 95%	✓	Achieved
11S-411	70.6%	< 95%	✓	Achieved

Figure 8.1: December 2024 Reliability Update Summary

In addition, the system reliability update summarizes the number of large storm days where large numbers of customers were impacted during the same event (see Figure 8.2). These events are linked to the increasing frequency and intensity of extreme weather events, and as such, are relevant to monitor as part of the climate adaptation process.

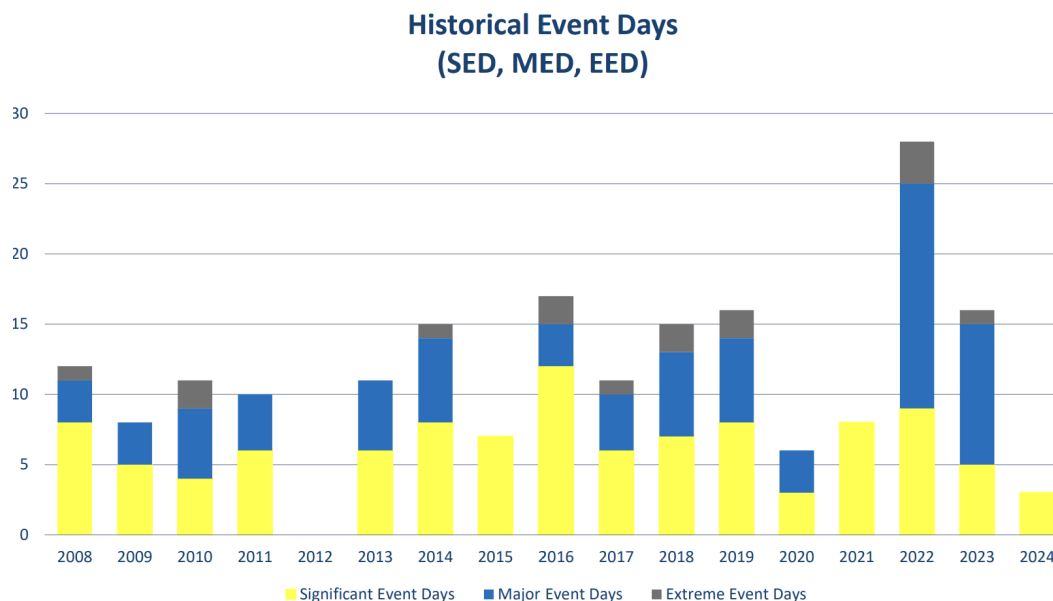


Figure 8.2: Number of Storm Days by Year

The following Figure 8.3 provides a summary of the CKAIFI²⁸ frequency, which is the number of customer hours of interruption by the number of customers served by the feeder. This information highlights the reliability performance of specific feeders and may require additional risk mitigation to address climate impacts.

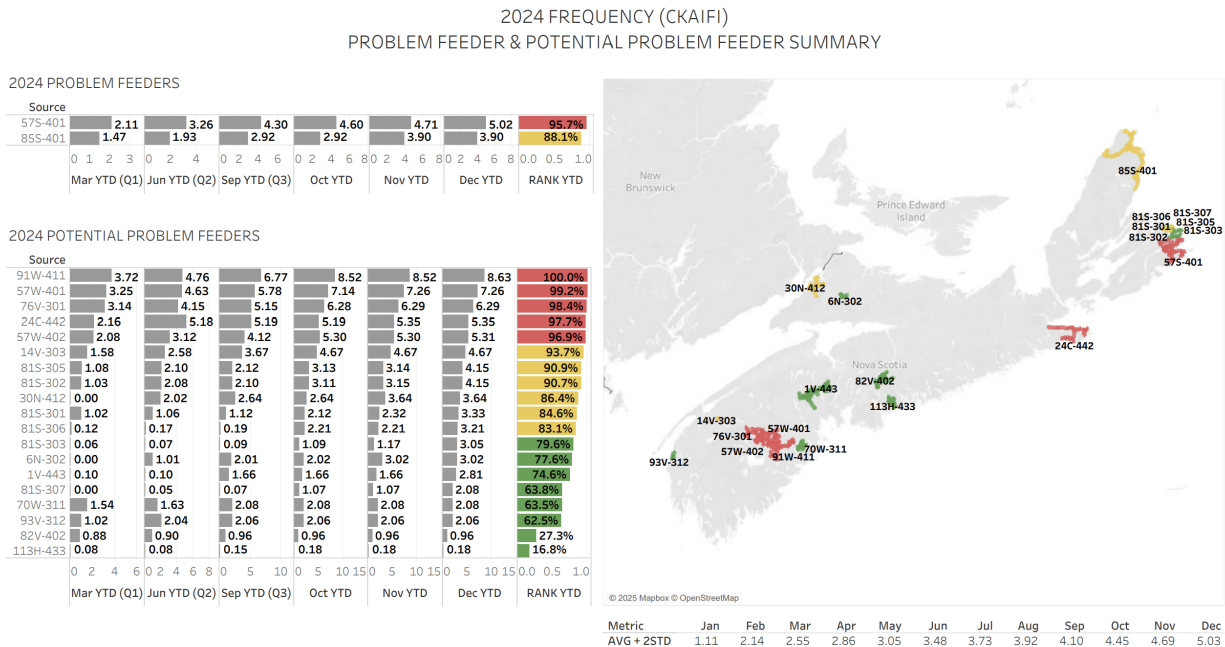


Figure 8.3: CKAIFI Statistics from December 2024

²⁸ Circuit Average Interruption Frequency Index

The following Figure 8.4 provides additional detail for a feeder which was flagged due to their reliability performance. The location of this feeder was previously discussed in [Step 4](#), as an area of the province that experiences the greatest number of windy days. The cause summary shows 24.1% of the events were caused by trees coming in contact with the lines. Moving sections of poles and conductors to roadside and widening ROWs, where possible, will increase the distance between the lines and vegetation. NS Power expects that risk mitigation to reduce the number of events on this feeder.

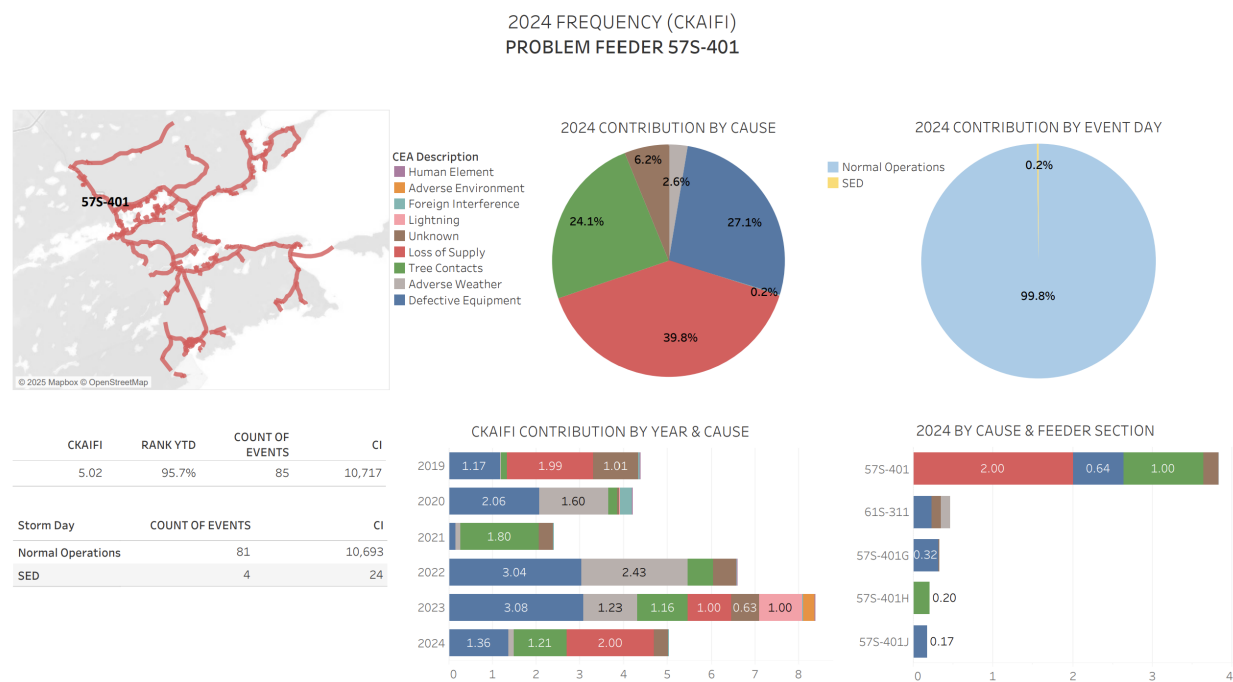


Figure 8.4: CKAIFI Results for Feeder 57S-401 in December 2024

For Generation, the monthly unit performance statistics are summarized on the high-capacity units, namely the fossil-fuel fired generating units as well as the Wreck Cove hydroelectric units. The following table provides a summary of the system availability and outage rates from 2024.

Table 8.1: 2024 Unit Performance Summary

Unit	Op Hours (Aligne)	Net Gen (MWh)	Avg Net Load Calc (MW)	Net CF Calc (%)	Cold Starts	Warm Starts	Hot Starts	DAFOR (%)	Availability Factor (%)
LIN-1	5,811	501,747	86	37%	9	8	5	5.2%	72.60%
LIN-2	2,155	162,792	76	12%	7	0	5	2.6%	93.8%
LIN-3	6,189	518,993	84	39%	6	8	5	0.1%	81.7%
LIN-4	4,600	375,971	82	28%	14	8	3	0.6%	79.6%
POA-1	6,630	782,438	118	53%	1	5	1	11.1%	76.5%
POT-2	5,829	563,036	97	43%	9	7	0	11.9%	78.2%
TRE-5	3,078	276,288	90	21%	7	1	2	14.0%	75.3%
TRE-6	6,053	581,956	96	43%	11	8	5	7.8%	84.9%
TUC-1	6,105	412,421	68	60%	11	0	1	5.6%	81.7%
TUC-2	5,491	401,817	73	49%	3	2	3	0.3%	65.7%
TUC-3	7,218	800,150	111	62%	4	5	0	4.1%	83.0%
TUC-4	7,707	274,996	36	64%	56	0	0	7.5%	89.5%
TUC-5	7,849	290,351	37	67%	23	0	1	2.2%	90.8%
TUC-6	6,940	189,557	27	47%	2	20	44	1.2%	87.7%
PHB-1	6,594	162,286	25	43%	6	14	24	6.7%	81.9%
BS-1			---	0%	96	0	0	93.9%	60.3%
BS-2			---	0%	87	0	0	23.5%	93.4%
BS-3			---	0%	75	1	0	39.8%	91.7%
BS-4			---	0%	51	0	1	19.0%	95.1%
VJ-1			---	0%	27	0	0	0.7%	98.3%
VJ-2			---	0%	26	0	0	40.2%	96.6%
TUS-1			---	0%	22	0	0	93.8%	73.4%
WC-1			---	0%	0	0	0	---	0.0%
WC-2			---	0%	0	0	0	9.0%	60.1%

As an input to the above data, there are weekly meetings to review and categorize all outage and derate events through Generation Equipment Reliability (GER, reference QP-G044) reporting for all generating units. This information is consolidated into the quarterly GER Reports. Within the GER reports there is an asset class selected for each event and some commentary on the cause of the equipment failure. The successful deployment of the Climate Adaptation Plan is expected to help manage some of the risks that may cause outages or derates of our generating units.

The GER report provides a source of information for the climate impacts that are contributing to system outages and unit derates. As an example, there was an outage for the Point Tupper (POT)

circulating water system caused by an excessive growth of zebra mussels. Warmer water temperature and large storms, related to climate change, can contribute to the growth of this invasive species.

As these outage events are reviewed, there may be a corrective action(s) identified by the asset management team to address the re-occurrence of that event. For some events, the action may be to summarize the event or complete a Root Cause Analysis (RCA) and communicate the findings to stakeholders including the relevant asset reliability team. The asset reliability team will then have a list of relevant asset failures at hand to further inform the annual risk scores for the assets within the relevant asset class.

8.2. Asset Reliability Team Asset Performance Reviews

The performance reports discussed above are reviewed annually by asset reliability teams to allow for changes in performance of the assets to be monitored. In addition, the asset reliability teams conduct annual health or condition assessments, as well as review of critical asset failures. The asset reliability teams are key in analyzing and understanding the climate information gathered in [Step 3](#) and are responsible for applying this knowledge through these reviews. If climate impacts are affecting the performance and/or condition of the assets, the asset reliability teams will identify that and make adjustments to the risk mitigation plans, as required.

The asset reliability teams will also provide the risk mitigation items that are entered into the CAMS. The annual documentation of the risk mitigation specifically targeting climate adaptation categories will be compiled and reviewed to enable further analysis of trends and to enable communication of the actions NS Power is taking to adapt to climate change.

CAMS is an in-house software solution which provides a place to store the climate risks identified in Step 3 and associated assets identified through Step 4. As risks are assessed through asset reliability teams as described in Chapter 5 (Step 3), NS Power captures its response within CAMS. This ensures that, while climate risks are evaluated with other risks through the asset management mechanism, they are also able to be singled out and reported upon as a unique grouping.

8.3. Continuous Improvement

NS Power's approach to climate adaptation utilizes existing programs and processes to ensure continuous improvement is achieved. The performance monitoring reports outlined above are one example of existing processes that provide the NS Power team with direction on areas to focus for continuous improvement.

As described in [Step 4](#), the asset management mechanism is another visual aid representing an ongoing process that clearly shows how continuous improvement is embedded in the NS Power asset management approach (see Figures 4.1 and 5.2). This evaluation is revisited by the asset reliability teams year-over-year but is also available for use as significant new information is available, or risks are identified. This evaluation can then trigger adaptation measures as described in [Step 5](#). This will serve the Climate Adaptation Plan well in terms of continuous improvement.

Another asset management function at NS Power that will support the continuous improvement of the Climate Adaptation Plan is the Root Cause Analysis (RCA) program. The RCA program monitors safety, environmental incident reports, as well as forced outage/derate reports via

participation in the GER reporting process for events that may require further analysis. In addition, investigations may be requested at any time by management, engineering or other personnel within the business. If major outages were to be caused by a climate impact, an RCA may be triggered. A series of recommendations would then be identified to reduce the likelihood of reoccurrence or reduce the future impact to the business for a similar set of circumstances.

The following Figure 8.6, taken from the NS Power SAMP, depicts continuous improvement of the NS Power asset management system. This figure outlines the approach to continuous improvement within the asset management system, which supports our climate adaptation plan.

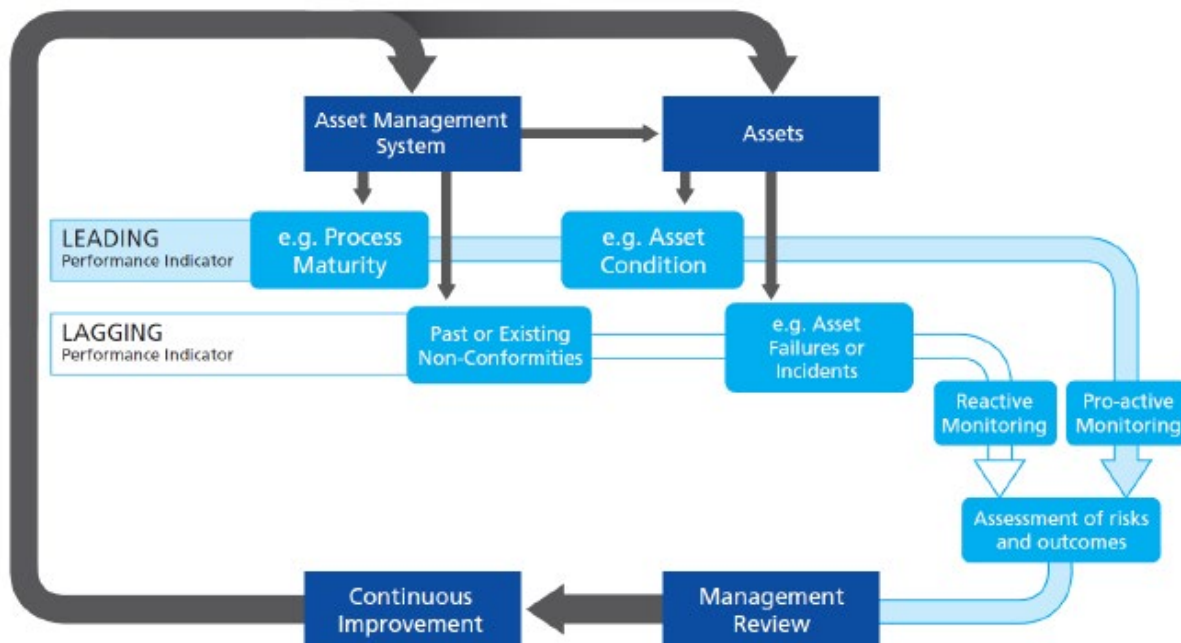


Figure 8.5: Assessment Performance of the Asset Management System Program and Processes

Performance reports, compliance reports, RCA reports, and engineering actions are all examples of existing asset management activities that will be utilized to promote continuous improvement of the Climate Adaptation Plan.

8.4. Climate Data

Chapter 1 of this plan detailed one of the goals of the Climate Adaptation Plan was to enhance NS Power's fundamental capacity to adapt to climate change by leveraging the best climate science and data available to inform NS Power's decision-making processes. To ensure this part of the plan is achieved, NS Power anticipates a regular check-in with expert third parties to validate existing climate datasets or to update those climate datasets when new relevant science is available.

In addition, NS Power understands the existing climate models are at times constrained based on the available present-day climate datasets. As such NS Power will commit, as part of the Climate Adaptation Plan improvement process, to enhance its current understanding of the climate within the Province through the following actions:

- **Monitoring Plan:** Creating a robust climate data and weather monitoring plan to continually collect observations of key climate variables;
- **Monitoring Resources:** Investigating what resources are available to dedicate to climate monitoring and, if resources limit the number of climate variables that can be monitored, selecting which climate variables to monitor (the ELAD prioritization may support this selection);
- **External Sources:** Building relationships or collaborations with academic, weather, and scientific organizations that may already be monitoring climate variables of interest;
- **Gather Data:** Reinforcing in-house monitoring teams and processes, for example, reinforcing or expanding smart meter program or other software or technology solutions; and
- **Benchmark Empirical Data:** As NS Power collects empirical data, it can be benchmarked against the trends provided by the projected climate data. This exercise may inform the pathway of climate change development.



WILDFIRE MITIGATION PLAN

2025 Update

Abstract

This report summarizes a best practice review of wildfire mitigation practices already implemented by NSP, as well as those to be considered for future implementation.

Enterprise Asset Management
Asset Reliability & Risk Management

Revision no.	Effective Date	Changes
0	Jan 5, 2022	
1	August 8, 2024	Updated formatting of mitigation plan. Added additional mitigation details to several sections.
2	April 4, 2025	Minor updates

Executive Summary

The purpose of the NS Power's wildfire mitigation plan is to reduce the risk of wildfires caused by electrical infrastructure in Nova Scotia and to protect public safety. It aims to ensure the reliability of electricity services by implementing strategies such as vegetation management, equipment upgrades, and operational changes. The plan focuses on preventing wildfires, minimizing potential damage, and enhancing the resilience of the electrical grid against future wildfire events.

The assets covered within NS Power's wildfire mitigation plan include:

- **Transmission Lines:** High-voltage power lines that transport electricity over long distances.
- **Distribution Lines:** Lower-voltage lines that deliver electricity to homes and businesses.
- **Substations:** Facilities that transform voltage levels and distribute electricity to different areas.
- **Rights-of-Way or Vegetation Management Areas:** Zones around power lines and equipment where vegetation is managed to reduce fire risk.
- **Monitoring and Control Systems:** Technologies and systems used for real-time monitoring and control of the electrical grid to detect and respond to wildfire threats.

This comprehensive scope ensures that all critical areas and assets are addressed, enhancing the overall effectiveness of the wildfire mitigation plan.

The main goals of the NS Power wildfire mitigation plan include:

1. **Reduce Wildfire Risk:** Minimize the likelihood of wildfires caused by electrical infrastructure.
2. **Protect Public Safety:** Ensure the safety of communities and individuals in wildfire-prone areas.
3. **Ensure Reliable Service:** Maintain the reliability and continuity of electricity supply during wildfire events.

The main objectives within the Wildfire Mitigation Plan for NS Power are summarized below.

	Risk Assessment & Mapping	Identify and prioritize high-risk areas for wildfires
	Situational Awareness	Maintain real-time awareness of conditions that could lead to wildfires.
	Inspection Programs	Regularly assess the condition of electrical infrastructure to prevent failures.
	Wildfire Risk Reduction	Strengthen electrical infrastructure to withstand wildfire conditions.
	Vegetation Management	Reduce the amount of flammable vegetation near electrical infrastructure.
	General Operating Practices	Adjust operational procedures to minimize wildfire risk.
	Emergency Response	Ensure rapid and effective response to wildfire incidents.
	Continuous Improvement	Outline of future initiatives and projects planned to further mitigate wildfire risk.

These goals and objectives work together within this wildfire mitigation plan to create a comprehensive approach to wildfire prevention and response, ensuring both safety and service reliability.

The long-term vision of a wildfire mitigation plan for NS Power is to create a resilient and sustainable electrical grid that can withstand and adapt to wildfire risks. This vision includes:

1. **Enhanced Safety:** Achieving a continued low number of wildfire incidents caused by electrical infrastructure in NS, ensuring the safety of communities and ecosystems.
2. **Reliable Service:** Maintaining uninterrupted and reliable electricity supply even during high-risk wildfire conditions.
3. **Innovative Technology:** Integrating advanced technologies such as smart grids, real-time monitoring systems, and predictive analytics to proactively manage wildfire risks.
4. **Community Partnership:** Fostering strong partnerships with communities, local governments, and stakeholders to collaboratively address wildfire challenges and enhance public awareness and preparedness.
5. **Continuous Improvement:** Regularly updating and refining mitigation strategies based on the latest research, data, and technological advancements.

This vision aims to ensure long-term safety, reliability, and sustainability in the face of evolving wildfire threats. At NS Power, we are steadfast in our commitment to reducing wildfire risk and protecting the communities we serve.

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1.0 Introduction

The purpose of the NS Power's wildfire mitigation plan is to reduce the risk of wildfires caused by electrical infrastructure in Nova Scotia and to protect public safety. It aims to ensure the reliability of electricity services by implementing strategies such as vegetation management, equipment upgrades, and operational changes. The plan focuses on preventing wildfires, minimizing potential damage, and enhancing the resilience of the electrical grid against future wildfire events.

The main elements within NS Power's wildfire mitigation plan are summarized below, and are expanded upon in the following sections of the plan.

	Risk Assessment & Mapping	Identify and prioritize high-risk areas for wildfires
	Situational Awareness	Maintain real-time awareness of conditions that could lead to wildfires.
	Inspection Programs	Regularly assess the condition of electrical infrastructure to prevent failures.
	Wildfire Risk Reduction	Strengthen electrical infrastructure to withstand wildfire conditions.
	Vegetation Management	Reduce the amount of flammable vegetation near electrical infrastructure.
	General Operating Practices	Adjust operational procedures to minimize wildfire risk.
	Emergency Response	Ensure rapid and effective response to wildfire incidents.
	Continuous Improvement	Outline of future initiatives and projects planned to further mitigate wildfire risk.

Wildfire seasons are getting longer and more severe due to climate change. Pacific Gas & Electric (PG&E) in California filed for bankruptcy in 2019 to deal with an estimated \$30 billion US in liabilities from wildfires that their equipment may have ignited in 2017 and 2018. Proactive prevention, mitigation, and preparedness are all methods for utilities to maintain safe systems, limit liability, and protect their assets.

In 2023, Nova Scotia saw the largest wildfire in its history impact Shelburne County with over 23,000 hectares of land burned. Additionally, major fires in Tantallon simultaneously impacted hundreds of residences. In Canada there was over 17,000,000 hectares burned in 2023, as shown in Figure 1, more than doubling the previous high in 1995.

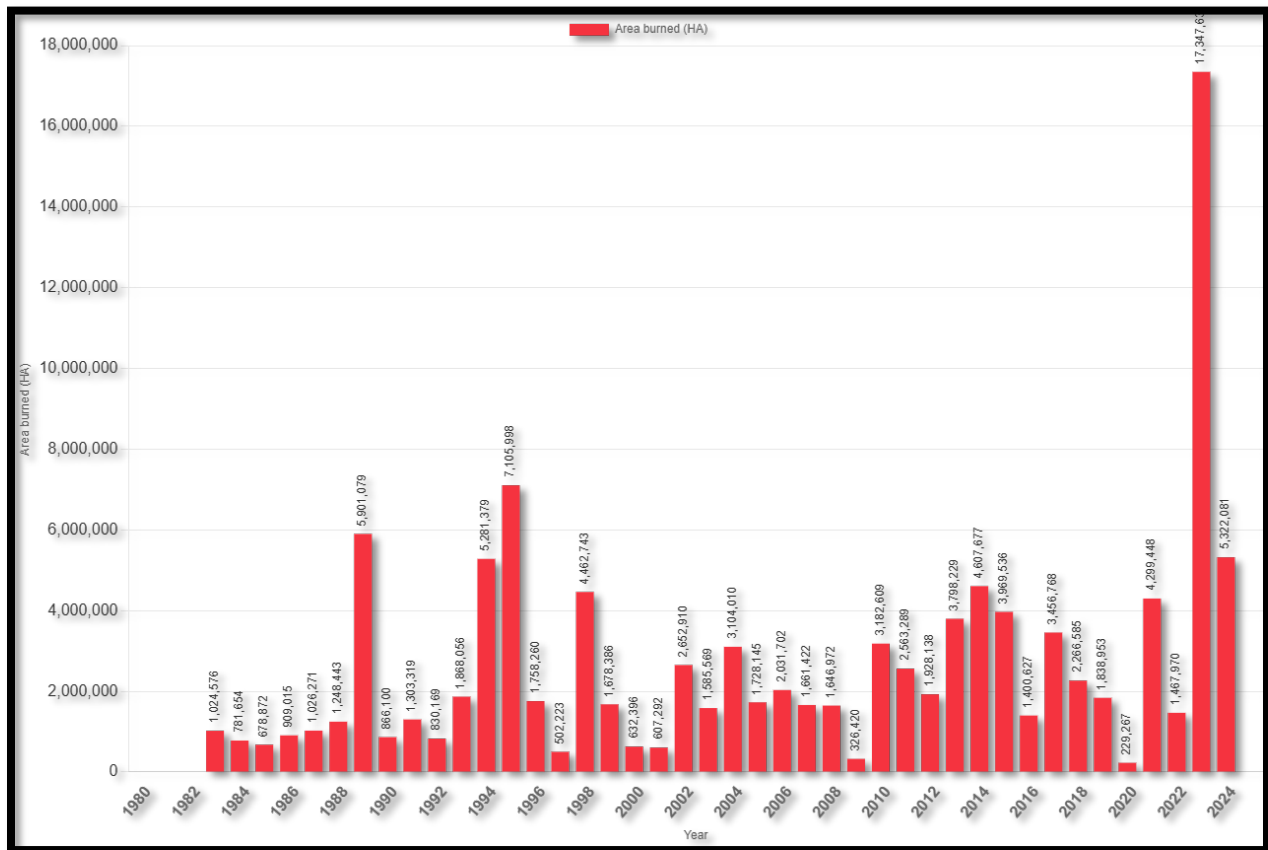


Figure 1: Annual area burned in Canada by wildfires (Source: Canadian Interagency Forest Fire Centre Inc. (CIFFC))

This document outlines the best practices at Nova Scotia Power to mitigate wildfires and minimize their impact on our customers. The practices listed in this report are gathered from various subject matter experts (SMEs) at NS Power. This includes SMEs from transmission, distribution, forestry, and substations. Furthermore, the NS Power team continues to review industry best practices to ensure continuous improvement opportunities to further enhance our wildfire risk management practices are identified.

2.0 Nova Scotia Wildfire Risk Assessment

Wildfire risk in Canada is determined at a primarily national level; and generally, provincial climate and environmental conditions mean Nova Scotia has a much lower risk for wildfires compared to higher risk provinces of BC, Alberta, Saskatchewan, and Manitoba.

2.1 Wildfire History in NS

For Nova Scotia specifically we reference the [Canadian Wildland Fire Information System](#) to understand the level of wildfire risk. In Figure 2, the Fire Weather Index normals for Nova Scotia is in the “Very Low” to “Moderate” ratings based on historical data from 1981 to 2010. Figure 3 illustrates the low number of large forest fires within these same service areas relative to other parts of Canada, with the data representing the period from 1980 to 2021.

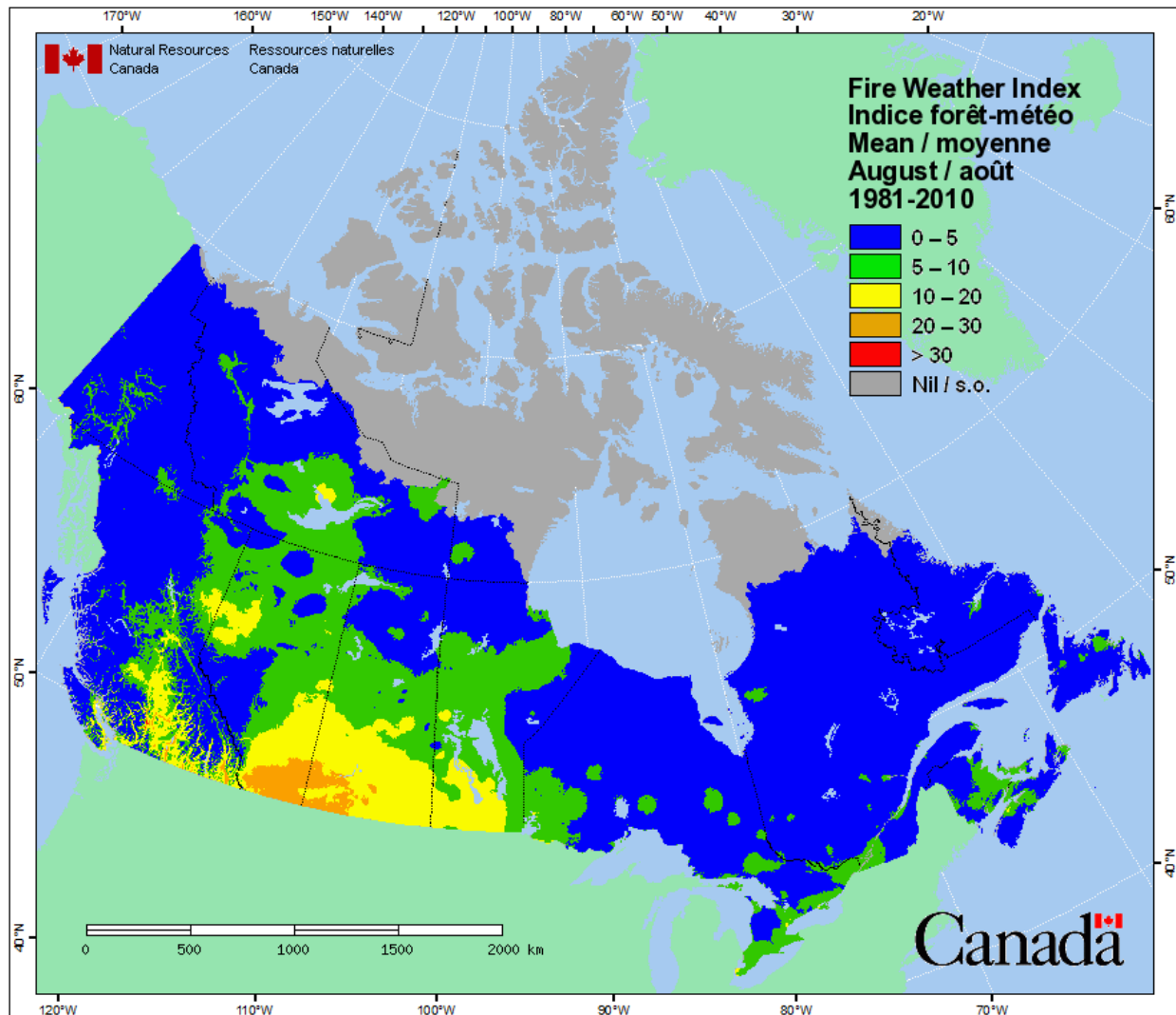


Figure 2: Fire Weather Normals represented by the average value of a fire weather index from 1981 to 2010.¹

¹ [Canadian Wildland Fire Information System | Fire Weather Normals \(nrcan.gc.ca\)](#)

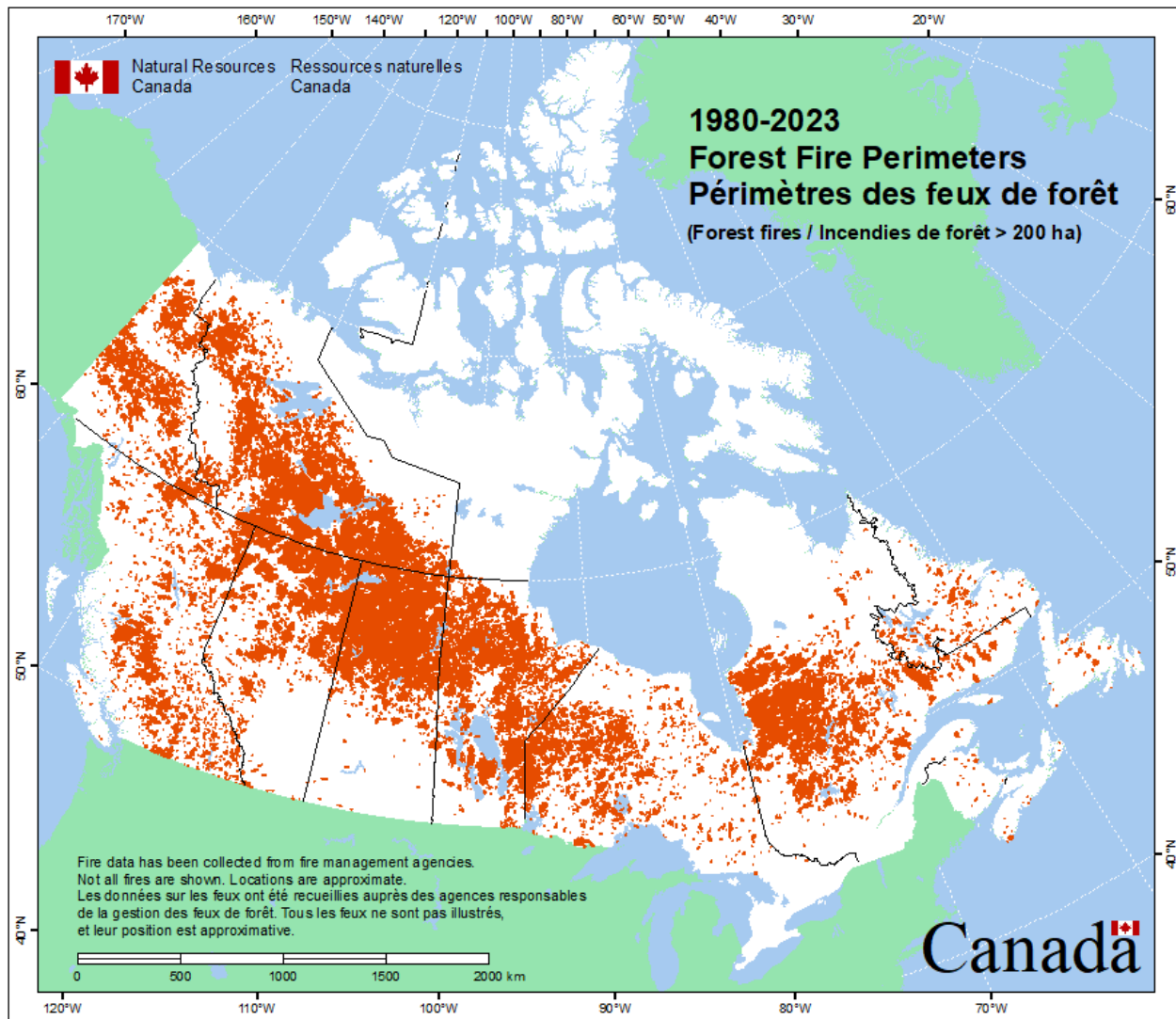


Figure 3: Depiction of >200 hectares fires in Canada from 1980-2023 (NRCan)²

The NS Department of Natural Resources and Renewables (NRR)³ provided the following information about wildfires in Nova Scotia:

- Nova Scotia experiences an average of 225 wildfires of all sizes each season.
- Fire locations are correlated to areas of greater population density. Wildfires are generally started due to human activities with relatively few (about 3%) fires started by lightning.
- Fire season in Nova Scotia is March 15 to October 15, with May usually the most active month. In this period, vegetation is still somewhat dormant and the moisture content of these fuels is low, making them are more flammable. This is known as a "before green up" condition.

² [Canadian Wildland Fire Information System | Canadian National Fire Database \(CNFDB\) \(nrcan.gc.ca\)](https://www.nrcan.gc.ca/wildland-fire-information-system/cnfdb)

³ [Wildfire | novascotia.ca](https://www.wildfire.novascotia.ca)

- Nova Scotia has a relatively wet climate, thus the number of fires that typically occur in an average season is low compared to drier provinces in Western Canada.

NRR also tracks wildfires occurring in Nova Scotia each year. This includes the number of wildfires in an area, the cause of the wildfire, and how many hectares were burned. Table 1 shows the data NRR has collected for fires caused by powerline equipment. As shown in the data, there are only a small number of fires attributed to power lines each year in Nova Scotia, and these instances have not led to any significant wildfires. The specific circumstances behind each event have not been validated by NS Power.

Table 1: Fires caused by powerlines in Nova Scotia⁴

Year	# of Powerline Caused Fires	Hectares Burned
2024	5	1.28
2023	21	Unknown
2022	7	3.75
2021	8	0.48
2020	15	Unknown
2019	8	0.88
2018	11	6.96
2017	11	1.8
2016	12	3.77
2015	7	47.06
2014	6	2.47
2013	4	2.35
2012	3	0.31

As previously noted, fire season in Nova Scotia is considered to run from March 15 to October 15 with the month of May usually the most active month. In this mid to late spring period, vegetation is still somewhat dormant, and the moisture content of these potential fuels is low, making them more flammable and prone to wildfire ignition and spread. This is known as a "before green up" condition. As vegetation in the province begins its more active growing season, moisture content increases, and wildfire risk abates significantly. Furthermore, Nova Scotia has a relatively wet climate, thus the number of fires that typically occur in an average season and the opportunity for significant spread is low compared to drier provinces. While current climate projections indicate that overall annual precipitation in NS is expected to increase slightly over the coming decades, future years will likely be interspersed by longer periods of drought between major

⁴ [Nova Scotia Wildfire Statistics | novascotia.ca](https://novascotia.ca/nrr/wildfire-statistics)

rainfall events. The net impact on wildfire risk from these factors is discussed in Section 2.2 Climate Modelling

2.2 Climate Modelling

NS Power has completed Climate Modelling to understand how the inputs for wildfire risk will change into the future. This includes precipitation levels, temperature, and wind speeds. These climate risks are integrated into NS Power's Risk Frameworks and used to develop mitigation strategies, including but not limited to, directing capital investment. Through the climate adaptation planning process, the company has preliminarily evaluated the potential impacts from wildfire on our infrastructure. Based on the available climate models and understanding, current wildfire risk across our service area is deemed to be low.

Willis Tower Watson's Climate Hub (formerly Acclimatise) provided data on how Fire Weather Index (FWI) is predicted to change into the future. Table 2 shows the number of days with an FWI above 10 during wildfire season. The data predicts a minimal increase in the number of days with wildfire risk in the future. This is a result of longer periods of drier conditions during the summer months compared with historically more favourable conditions in the past.

Creating a risk map increases the awareness of wildfire risk and assists in decision making. GIS climate maps have been created for Nova Scotia using data from a third-party climate change company, Acclimatise. These maps show the localized FWI values for different climate scenarios as well as the average number of days that have a high FWI over a year period. The maps can be used to illustrate what areas in Nova Scotia have the highest historical and predicted future FWI values potentially leading to more frequent and/or severe wildfires occurring in that given area. Fortunately, Nova Scotia Power's climate projections suggest no significant change in the total number of days in NS with a FWI rating greater than 10 or a 'High' rating during wildfire season.

Table 2. Number of Days Above an FWI of 10 During Wildfire Season

Month	Present Day	2030s	2050s
March	0.18	0.15	0.20
April	1.32	1.76	1.82
May	4.16	4.30	4.30
June	7.37	7.52	7.52
July	9.71	9.89	9.99
August	9.16	9.54	9.54
September	6.31	6.71	6.79
October	1.43	1.63	1.58

Please refer to section 4.1 for additional information on the FWI.

Generally, Nova Scotia is a wet coastal environment that sees annual precipitation in the range of 1,315 mm per year. Climate projections show a slight increase in total annual precipitation for Nova Scotia in future decades, as shown in Table 3.

Table 3: Nova Scotia future precipitation estimates⁵

	Baseline (1981-2010)	2050s (2035-2065)	2080s (2065-2095)
Annual Precipitation	1315 mm	1401 mm (+ 6%)	1456 mm (+ 11%)
Days with Rain	112	124	132
Days with Snow	39	25	17
Days with > 1 mm	151	150	149
Days with > 20 mm	16	18	20
Max 1-day	53 mm	60 mm	63 mm
Max 5-day	90 mm	99 mm	105 mm

As a result of the combination of FWI, precipitation, and Standardized Precipitation Index (SPI) projections Nova Scotia is not expected to see a dramatic change in the level of wildfire risk conditions in the future.

The SPI projections for NS indicate a trend towards moderately dry conditions, with values typically ranging from -0.99 to -1.12 through the 2050s. These SPI values suggest a persistent deficit in precipitation, which can exacerbate drought conditions and increase the risk of wildfires. But, on the scale of relative values, we are not expected to face severely dry or extremely dry conditions.

2.0+	extremely wet
1.5 to 1.99	very wet
1.0 to 1.49	moderately wet
-.99 to .99	near normal
-1.0 to -1.49	moderately dry
-1.5 to -1.99	severely dry
-2 and less	extremely dry

3.0 Risk Mapping

Mapping wildfire risk in the vicinity of utility assets is essential to inform the most appropriate mitigation strategies to prevent fires from occurring and managing at-risk assets during fire season. Using wildfire risk mapping, NS Power can identify locations where strategic prevention and mitigation efforts will see the most benefit.

⁵ Reference: Data presented to Climate Adaptation Leadership Program: Electricity Sector by NSECC in 2022.

3.1 Enhanced Risk Profiling

A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment

NS Power has detailed risk profiles of our transmission lines and distribution feeders across its service territory. These risk profiles can be overlaid with wildfire risk considerations where applicable and as such provide insight on areas with potential for greater wildfire risk. Risk profiles for NS Power assets are updated as new data becomes available, at least on an annual basis, and these risk profiles include both lagging indicators such as wildfire caused outages, and leading indicators, such as vegetation encroachment into rights-of-way. Please see Figures 4 and 5 for sample risk profiles for transmission and distribution lines respectively.

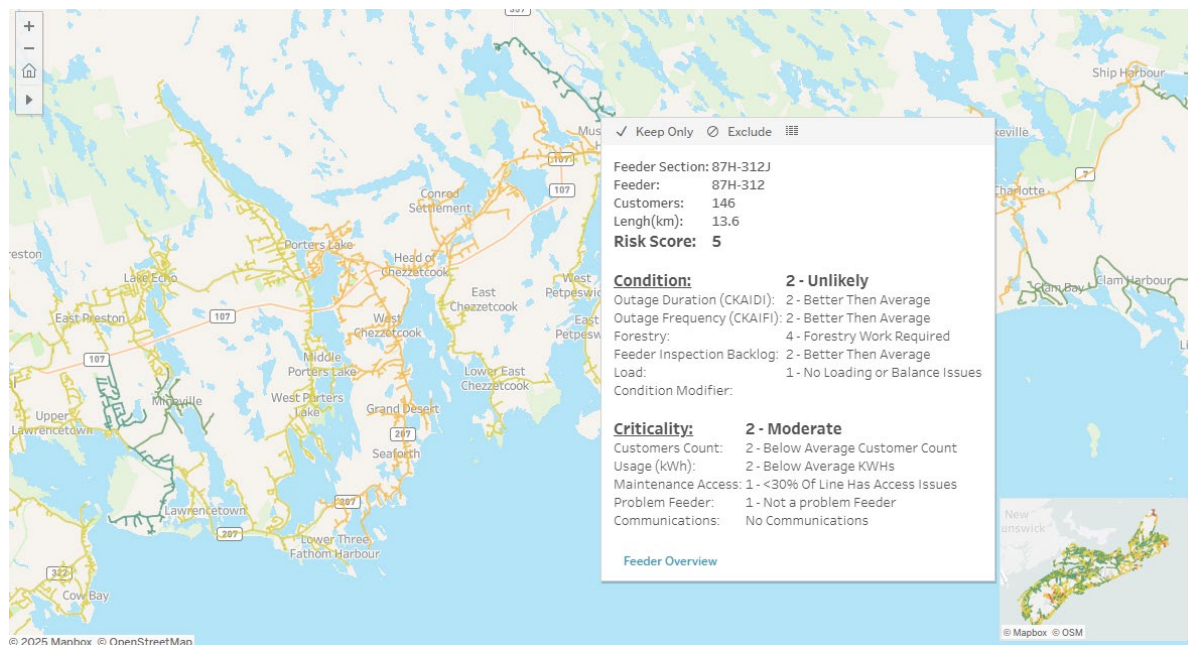


Figure 4: Sample from NS Power Distribution Feeder Risk Profiles

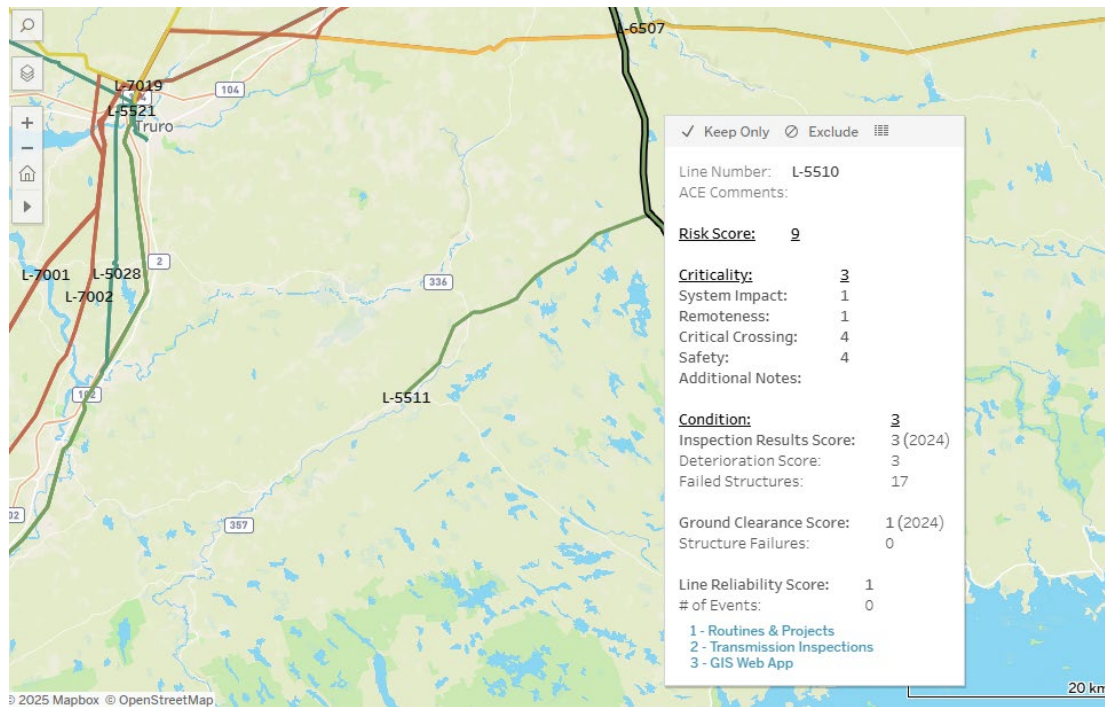


Figure 5: Sample of NS Power's Transmission Line Risk Profile

3.2 Tracking and analysis of wildfires and near miss ignitions

The purpose of this practice is to track ignitions and potential ignitions and perform root cause analysis to detect and understand patterns or correlations. The resulting data can then be used to help inform and refine future fire prevention decisions.

On a regular basis, NS Power receives forest fire data from NS NRR on any wildfires believed to be attributable to power line infrastructure as the cause of the fire. These items are reviewed by the Vegetation Reliability Team and assessed for any trends or prioritization of vegetation management activities.

Through NS Power's Outage Management System all outage events are tracked and categorized with all relevant information, including its cause. Consequently, a particular outage related to a wildfire can be analysed with respect to root cause.

3.3 Ignition probability

Utilities in North America are developing and using tools and processes to assess the risk of ignition across regions of the grid (or more granularly, e.g., circuits, spans, or assets). Power lines contribute to wildfires in several ways, including trees contracting lines during high wind events; high impedance faults causing fires when conductors hit the ground without blowing a fuse or

tripping a protective device; branches spanning two phase conductors; conductor slapping; and repetitive faults.

As described in section 2.1, NRR provide annual statistics on powerline related wildfire incidents, and these continue to cause a very small percentage of the total number of wildfires in NS each year. The small number of powerline-related wildfires in Nova Scotia are most commonly a result of one of the following three conditions:

1. Trees touching powerlines either by wind or growth;
2. Failed insulator on a utility pole which then causes the pole to catch fire; and
3. Energized downed powerlines.

When fires occur as a result of NS Power equipment, they are generally contained quickly by PLTs or other emergency responders. This is shown in the NS stats as the acres burned associated with the powerline fires is relatively low (see Table 1 above).

Vegetation contacting overhead electrical equipment is the number one contributor leading to ignitions by NS Power equipment. Specifically, vegetation encroachment on bare secondary wires has led to previous documented ignitions. Due to the typically smaller vegetation clearances required, distribution equipment has historically been more likely to be an ignition source than transmission equipment. Although NS Power has not developed a specific wildfire ignition probability assessment to date, rights-of-way risk profiles (refer to section 4.1) provide an indirect measure of ignition likelihood. These risk profiles factor in the condition of vegetation within the right-of-way, with areas of increased growth and potential for tree contacts assigned a higher risk level. NS Power targets higher risk areas for vegetation management activities, as well as other capital investments, such as relocating a line to roadside, as appropriate.

4.0 Situational Awareness

The centralized aggregation of data from power system assets provides visibility into the state of the power system so that appropriate actions can be taken to match fire risk conditions. Understanding this state when a fault occurs on equipment allows for a quicker response to a potential ignition source. Enhancements to situational awareness, including increased visibility to downline protective devices, would improve NS Power's ability to respond in future.

4.1 Fire Weather Forecasts

In terms of near real-time wildfire risk, Nova Scotia Power leverages available wildfire forecasts and risk maps provided by the provincial government ([Fire Weather Forecast Maps and Indices | novascotia.ca](https://www.novascotia.ca/naturalresources/fireweather)). The Department of Natural Resources and Renewables provides Fire Weather Forecasts daily. Their weather stations provide a Fire Weather Index (FWI) value associated with

different areas across Nova Scotia. There are 31 weather stations (see Figure 6) that collect the data used in the FWI calculation. The FWI classifications for Nova Scotia are shown in Table 4.

The Fire Weather Index (FWI) within these Nova Scotia datasets factor in observations from the 31 weather stations measuring temperature, relative humidity, wind, rain, as well as assessing the moisture in vegetation.



Figure 6: NRR Weather Stations in Nova Scotia in relation to NS Power transmission lines

The primary tool used in Canada by all fire management agencies to track and map fuel moisture conditions across their jurisdictions is the Canadian Forest Fire Weather Index (FWI) System. This system consists of six components that account for the effects of fuel moisture and weather conditions on fire behavior. Table 4 provides the FWI Index in Canada as well as the ranges specific to Nova Scotia.

Having high coverage of FWI data across Nova Scotia and procedures in place for different situations allows for informed operational decisions to be made. There are already some operational groups who review the FWI values daily during wildfire season currently such as Forestry⁶ and their actions in the field are adjusted accordingly.

⁶ Vegetation Management Operating Procedure VM2.05, Fire Season (June 30, 2014)

As per our Forestry operating practices, during any period where the index reaches a rating of **Moderate** or above for the area(s) in which vegetation management activities are ongoing, a daily review of fire risks is necessary. A formal record of the daily hazard rating for the area in which the activity is occurring is to be maintained on site by the Contractor and be made available for audit by NS Power.

Whenever the fire hazard index rates the hazard as **High**, documented daily inspections for adequacy and functionality of fire-fighting equipment on each job site are to be conducted by the Contractor. This documentation is to be maintained on site by the Contractor and be made available for audit by NS Power.

Whenever the fire index reaches **Very High** for the area in which an operation is taking place, and remains so for more than two consecutive days, modified hours shall be put into effect on the third day and remain so until such time as the hazard rating subsides to **Moderate**. Under Modified hours, all vegetation management operations are to be shutdown daily by 1:00 pm. A fire watch is to be maintained on site for 1-hour following such shutdown.

Whenever the index reaches **Extreme** in NS:

- All cross-country (distribution & transmission) operations will be shut down until such a time as the index drops to a maximum of **Very High**.
- Roadside operations may proceed based on joint agreement between the Forestry Coordinator responsible for the job, System Forester, and the Forestry Manager.

Table 4. Nova Scotia Fire Weather Index (FWI) Classification

Risk Classification	FWI Range in NS	FWI Ranges from Natural Resources Canada
Low	0-3.9	0-5
Moderate	4-9.9	5-10
High	10-16.9	10-20
Very High	17-22.9	20-30
Extreme	≥23	>30

NS Power's operational teams refer to the Nova Scotia Department of Natural Resources and Renewables [Fire Weather Forecast](#) and its Fire Weather Actuals, to maintain active awareness of the current and near-term wildfire risk present throughout the service area.

In addition, NS Power has contracts in place with meteorological services companies to provide daily weather forecasts. These daily forecasts allow for our internal team to identify potential

meteorological risks and assess when weather conditions may cause an impact on our infrastructure. This allows the company to mobilize appropriate field resources to address any potential events.

Should the FWI increase substantially in a particular section of its service area, NS Power may adjust its operations, limiting high risk work and/or removing personnel from the high wildfire risk areas in consultation with internal and external stakeholders.

Utilization of situational awareness tools such as weather stations, cameras, and the Fire Weather Index have shown to be beneficial for utilities in system planning and emergency operations. A critical component of wildfire mitigation is the ability to assess and forecast the fire risk based on weather conditions and other environmental factors. These variables are dynamic, and accurate forecasting requires processing a large amount of data from multiple sources.

4.2 Wildfire Tracking

There are several publicly available maps to allow for daily tracking of active wildfires across Canada. Ongoing fire activities such as local fire bans, advisories and active wildfires, and provide additional near-real-time information to NS Power's control center regarding current wildfire risks. NS Power has integrated wildfire tracking maps into the internal GIS mapping, making it easier for employees to assess wildfire locations. Here's a list of the maps that may be utilized during active wildfires:

- Wildfire Nova Scotia Viewer, Department of Natural Resources and Renewables – Forest Protection, <https://experience.arcgis.com>
- Situation Report, Canadian Interagency Forest Fire Centre Inc, <https://ciffc.net/situation/>
- Interactive Map, Canadian Wildland Fire Information System, Natural Resources Canada, <https://cwfis.cfs.nrcan.gc.ca/interactive-map>
- Canada Wildland Fires, MappingSupport.com, <https://mappingsupport.com/p2/>
- Smoke Forecast, FireSmoke, <https://firesmoke.ca/forecasts/current/>

4.3 Personnel Monitoring

NS Power's field resources working across NS Power are subject to the Automatic Vehicle Location (AVL) Policy, where fleet vehicle locations are monitored. During an emergency event such as a wildfire, NS Power has direct access to quickly identify what field resources may be in proximity to elevated fire risk conditions, and they can be contacted to both inform operational decisions through field observations as well as notifying personnel of the potential wildfire risk.

5.0 Inspection Programs

Inspection and maintenance programs enable utilities to identify and address deficient conditions and components to reduce potential impacts to the electric system, minimizing hazards, and maintaining system reliability. Existing condition assessment programs should be reviewed for continuous improvement opportunities and new programs should be identified and considered for incorporation as appropriate.

5.1 Ground Patrol Inspections

Detailed inspections of electric lines and equipment

Careful visual inspections of overhead electric lines and equipment where individual pieces of equipment and structures are carefully examined, visually, and through use of routine diagnostic test. For distribution circuits, deficiencies are collected by exception for prioritization and corrective action. For transmission lines, the condition of each structure and span (including vegetation condition) is rated and recorded.

Inspection programs are used to identify potential future equipment failures or vegetation contacts which can be ignition sources. For transmission, the following equipment and structures are assessed and documented during inspections: wood frame structures, steel lattice structures, steel pole structures, line disconnect switches, insulators, contacts, leads and grounds. For distribution, the feeder equipment that are assessed are: arrestors, capacitors, control boxes, conductors, cut-outs, framing, guys, insulators, metering tanks, poles, reclosers, services, step-downs, streetlights, switches, transformers, and voltage regulators. Vegetation impacts and wildlife interactions such as nesting are also inspected on the lines.

Quality assurance / quality control of inspections

NS Power uses a two-parts quality program. The first is quality control for the regular inspection programs to ensure they are being performed as planned and the inspectors are well-aligned with the inspection criteria. The second part relates to quality control of capital project work after completion. Examples of the latter would be checking if the correct design or equipment were installed following corrective action. This approach applies to both transmission and distribution programs. For distribution, efforts are in progress to improve the post-construction part of the quality control program for capital projects.

5.2 Helicopter Inspections

Helicopter inspections allow for an aerial perspective of overhead structures, conductor spans, and right-of-way encroachments. These inspections are designed to identify obvious structural or vegetation problems and hazards.

Helicopter inspections are used for transmission due diligence patrols to catch clearly visible risks. These are typically performed in the fall to help identify possible hazards, including potential ignition sources that can be mitigated ahead of wildfire season.

5.3 LiDAR Surveys

Accurate surveys of rights-of-way are critical for effective and appropriate line management. Light Detection and Ranging (LiDAR) data provides a detailed source of structure, conductor, and vegetation data for power line right of-ways as well as surrounding areas. This data can be used to address the on-going challenge of vegetation encroachment, and consequently wildfire mitigation. LiDAR data is a critical source for providing detailed and accurate assessment to support ROW vegetation management. LiDAR data is collected along a corridor and processed to identify areas that may result in clearance issues under particular line loading and/or weather conditions. This data can then be used to develop projects that are designed to raise structures and their associated conductors or to address the surrounding vegetation, decreasing the likelihood of "grow-in" or "fall-in" occurrences as necessary. A regular LiDAR inspection program is in place for high-voltage lines and is being evaluated for further expansion.

5.4 New Inspection Technologies

Drones are another technology currently being deployed at NS Power for inspections of our transmission and distribution lines. As drones collect video and still images, there is a combination of manual and AI approaches to review and identify deficiencies. Due to the additional angles and heights assessable by drone this approach can better detect certain equipment issues. Currently NS Power deploys drones for ad hoc detailed inspections of our transmission and distribution lines, as well as during emergency response scenarios, such as wildfire events.

Satellite imagery assessment is designed to assess vegetation condition across rights-of-way at a large scale that would be otherwise impossible using traditional techniques. By analysing this imagery through AI, the proximity of vegetation to distribution lines can be determined and areas of potential contact identified. This enables NS Power's vegetation management team to classify condition system-wide, integrate with feeder risk ratings, and effectively target corrective interventions across the province. Beyond improving overall vegetation management practice, potential wildfire ignition sources can be identified, prioritized, and addressed as appropriate. See section 7 for more details on Vegetation Management.

NS Power completed two pilots of satellite imagery to assess distribution vegetation condition over the past three years. The findings of these projects indicate that the use of this imagery analysis can deliver a sufficient level of detail for us in strategic and tactical vegetation management, including wildfire mitigation. NS Power is currently implementing a wider program province-wide in 2025.

5.5 Substation Inspections

Substation inspections are conducted primarily to identify and address reliability and environmental concerns but incidentally provides additional wildfire mitigation benefits. Specifically, the inspection program mitigates the risk of equipment failure by identifying equipment deterioration to undertake the repair or replacement before failure occurs. Equipment failure can lead to fires in oil-filled substation equipment, and while those fires are typically contained within the substation, any uncontrolled fires may pose an ignition risk.

The typical approach of substation design, with the use of steel structures, gravel, and concrete equipment bases makes it difficult for a fire to spread outside the substation. Furthermore, vegetation is removed around the exterior of the substation fence and gravel is extended outwards whenever possible. It would take a significant explosion force to cause flaming material to reach a surrounding area with fuel and power transformers are designed to prevent such large explosions from occurring.

6.0 Wildfire Risk Reduction

Components in poor condition are at higher risk of unplanned failure and should be prioritized for replacement or upgrade. Investment in maintaining or upgrading overhead lines will reduce the potential for transmission or distribution circuits or other equipment to cause wildfire ignition. Incorporating improved equipment and modern materials contributes to increasing hardening.

NS Power continues to make targeted, date-driven investments to make the electric system more resilient to wildfires and the broader effects of climate change. Examples include:

- Build-to-roadside programs;
- Right-of-way widening programs;
- Increased investment in vegetation management;
- Animal guards deployed on pole-top transformers and on substation equipment;
- Nest deterrents and standalone nest platforms;
- Equipment inspection and replacement programs
- Design and Construction Standards updates
- Drone and helicopter inspections during wildfire conditions to identify risks;
- Satellite monitoring of vegetation condition and encroachment; and
- Substation design and vegetation management to ensure appropriate fire breaks around substation locations.

6.1 Design Standards

Revising NSPI standards to bond hardware

Transmission Engineering has revised NS Power standards to bond all transmission hardware. With unbonded equipment, a structure's wood components contribute to structure insulation. If a flashover occurs, the arc quenching properties of the wood may cause a fire on crossarm and poles. Bonding all equipment adds more grounds to the structure and if a fault or flashover occurred in this case, it would trip the line, reducing the likelihood of wood components being impacted.

Pole hardening and replacement program based on pole loading assessment program

Actions are taken to remediate, adjust, or install replacement poles that the utility has identified as failing to meet modern safety factor requirements in accordance with utility standards in the NS Power's pole loading assessment program.

Updated pole design standards for all new transmission pole installations have been developed and adopted. These standards consider more severe loading for the 69 kV transmission poles. For distribution construction, the standards are reviewed periodically to determine whether they need to be updated. There is an enhanced design standard for coastal locations to withstand more significant storm events.

Substation Building Standards

Roofing materials are a major determinant of whether a wildfire will ignite a nearby structure. To protect NS Power's building assets, the targeted roof classification is "A", "B" or "C" where Fire Rating Classification "A" is recognized as the best in class, which includes metal roofs. Incorporating roof sprinkler systems on flammable roofs and maintaining internal building sprinkler systems where appropriate in high-risk fire areas is considered.

Control buildings at NS Power vary when it comes to design, fabrication, and construction. Some of the buildings are prefabricated and are delivered to site with composite roofing, some are steel frame designed with 20-year asphalt shingles and others are wood framed with steel roofs. NS Power's current standard specifies the use of asphalt shingles for all new construction.

Some substations are being retrofitted currently to use compressed inert gas as their fire suppression system. The Inergen suppression system protects enclosed areas by filling the room with gas and extinguishes any fire by lowering the oxygen content below the level that supports

combustion. It is recommended that substation control buildings continue to have fire suppression systems added and building designs to be reviewed and evaluated for whether more fire prevention measures are required.

6.2 System Hardening

Transmission structure maintenance and replacement

Remediation, adjustments, or installations of new equipment to improve or replace existing transmission structures (e.g., H-Frames, lattice steel towers, or tubular steel poles that support lines at or above 69kV).

NS Power has an existing inspection and maintenance program in place for all transmission structures.

Replacement of wooden poles

Replace wood poles that have deteriorated due to wear and/or pose a risk as an ignition source if they are subject to weather conditions that exceed their operating design standards. Poles in high-risk locations should be considered for replacement with materials that are more fire resistant such as steel, concrete, or composite material.

Wooden poles are inspected to identify deterioration and replaced using modern standards, including a suitable class of pole if required.

Different pole materials have been discussed before future use in transmission such as steel, concrete, and fiberglass. NS Power's transmission system is currently a combination of steel and wood structures. While alternative pole types are more expensive than wood, they are considered for replacements in high-risk areas.

Covered conductor installation

Covered conductors act as a physical barrier between electrical equipment and vegetation, animal contact, and other external contacts. This reduces the possibility of power line arcing or sparking if contact occurs. Hendrix cables are a type of covered conductor that has helped other utilities with such risk reduction. Cover-ups are currently applied in a limited number of targeted locations on distribution lines for NS Power. Expanded use of covered conductors is under consideration.

Circuit Breaker replacement

Replacing aging substation infrastructure such as obsolete 138kV and 69kV substation circuit breakers, electro-mechanical relays, and Remote Terminal Units (RTUs) ensures your protection and control equipment is functioning effectively, and reduces the risk of faults that could initiate a wildfire. Circuit breakers are inspected and replaced when conditions require.

Lightning arrestor removal and replacement

Lightning arrestors are a piece of electrical equipment designed to mitigate the impact of transient overvoltage on the electric system. Overvoltage can cause damage to more expensive equipment, therefore lightning arrestors are used as protection devices. However, if the overvoltage duration is too long or too high, the arrestor can become thermally overloaded, causing failure and a potential ignition source. From climate projection data, it is predicted that lightning activity in Nova Scotia will increase in the future.

Lightning arrestors are used on all main pieces of equipment as a standard for distribution (i.e. transformers, reclosers, etc.). Transmission lines use grounding wires instead of lightning arrestors. Substations use a higher class of arrestors that do not generally pose an ignition risk (in part due to substation vegetation management).

New arrestor designs reducing the potential of becoming an ignition source should be evaluated for inclusion into distribution standards as applicable.

Crossarm replacement

Installations of new equipment to replace existing crossarms, defined as horizontal support attached to poles or structures generally at right angles to the conductor supported.

NS Power deploys an inspection program for transmission and distribution equipment (including crossarms). Crossarms are assessed for condition and replaced as appropriate. A new transmission standard now in place allows for the replacement of wooden crossarms with a steel version, to further reduce the risk of a steel arm contributing to a wildfire initiation.

6.3 Wildlife Protections

In addition to interruptions, wildlife interaction with electrical equipment can lead to ignitions. Installation of bird and wildfire deterrents on structures and assets are used to reduce the

likelihood of these interactions. NS Power employs a series of initiatives to reduce the risk of wildfire caused by wildlife interactions with our infrastructure. This includes:

- Wildlife guards on all new pole-top transformers
- Line covers
- Nest deterrents on poles
- Alternate nest platforms
- Line markings (e.g. bird flight diverters)

Appropriate wildlife protection methods depend on the assets present on the system. These are summarized in Table 5.

Table 1. Wildlife Mitigation for NS Power Equipment

System	Wildlife Interaction	Mitigation Used
Substations	Animals interfering with the substation equipment, specifically birds.	Installation of animal guards at some substations. These are applied to reduce locations where animals may bridge gaps between energize equipment and ground. NS Power plans to continue retrofitting deterrents for high-risk substations and have the deterrents installed at all new substations.
Transmission	Most common type of interaction is birds nesting on the lines or flying into lines.	There are deterrence spikes that are placed on the cross arms to reduce interaction. Bird diverters are mainly used for T-lines. They are being installed for any new installs across water crossings. When a bird nest is determined to be a hazard, it is removed. A nest platform nearby is then installed to prevent nesting on the transmission structure from occurring again.
Distribution	Birds are the main source of wildlife interfering with equipment.	A standard for nesting and perching deterrents is in place and is used in areas where nesting has been observed. Transformer animal guards are installed on all new pole-top transformers. For in-service transformers, after a wildlife caused outage guards are installed. Bird wire is also installed at some locations to prevent interactions with jumpers.



Figure 6: Wildlife protections on distribution



Figure 7 – Alternate nest platform



Figure 8 – Nest deterrents installed on top of distribution pole

6.4 Personnel Training

Personnel work procedures and training in conditions of elevated fire risk

Work activity guidelines that designate what type of work can be performed during operating conditions at different levels of wildfire risk.

Designate the type of work activities that may be performed in its territory during certain operating conditions (Normal, Elevated, Extreme). As conditions increase in severity, activities that present an increased risk of ignition have additional mitigation requirements. Where risk cannot be mitigated, work activity might cease.

- Normal – normal operating procedures are followed with baseline tools and equipment
- Elevated – certain at-risk work activities may require additional mitigation measures in order to proceed with work. The additional mitigation measures will be documents
- Extreme – most overhead work activities will cease, except where not performing the work would create a greater risk than doing so. In those cases, a designated coordinator for emergency work would be consulted and additional; mitigation steps implemented.

NS Power's *Vegetation Management Operating Procedure VM2.05* provides formal guidelines on what vegetation management work can be done under different wildfire risk conditions. The Forestry team currently reviews the FWI forecast and will proactively limit their activities according to their procedure. Field level risk assessments are conducted to determine specific risks, and based on these assessments, activities are reviewed by the Safety team. Temporary limitations, such as not driving all terrain vehicles in rights-of-way, are enacted when a risk is identified. Additionally, some contractors are subject to certain restrictions depending on the fire risk, such as what time of day work can proceed.

Crew-accompanying ignition prevention and suppression resources and services

Those firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, and water) that are deployed on construction crews provide site-specific fire prevention and ignition mitigation during on-site work. NS Power crews carry appropriate fire suppression equipment in case of small fires breaking out. If a larger fire results from construction work or if a fire is approaching a work site, it is not expected for crews to undertake fire suppression; instead, firefighters will be contacted to address the situation. The Forestry team engages with its contractors at the start of the annual fire season to ensure they have the necessary fire suppression equipment, as mandated by the NS Forest Fire Protection Regulations.

In addition to equipping crews with the necessary tools, NS Power emphasizes the importance of training and awareness. Personnel receive regular training on fire prevention, suppression techniques, and emergency response protocols. The Department of Natural Resources & Renewables ensures that contractors are well-prepared for fire suppression and integrates wildfire response into forest health prioritization. The Emergency Management Office (EMO) coordinates emergency preparedness and response efforts, fostering community resilience and ensuring effective communication during wildfire incidents. By working together, these organizations enhance the overall effectiveness of wildfire mitigation and response through training and awareness programs.

6.5 Proactive De-energization (Public Safety Power Shutoff)

NS Power is required to ensure the safe operation of the transmission and distribution system and has the authority to interrupt circuits for various public safety risks including wildfire. Furthermore, emergency management organizations may request NS Power to de-energize circuits in consultation with the Energy Control Centre. In the past, NS Power has employed manual power shutdown through direct engagement with the Nova Scotia Department of Natural Resources and Renewables and other emergency management organizations when there are active wildfires and firefighting activities in proximity to NS Power equipment.

The decision to shutdown power is made by the NS Power System Operator who has ultimate responsibility for the NS Power system. NS Power engages with government emergency management organizations to assess the risk of wildfire and interrupts power circuits, as necessary.

NS Power has shut down power during emergency response to active wildfires through direct engagement with Provincial Government emergency management organizations during major wildfires in recent years.

NS Power is in the process of integrating the following Public Safety Power Shutoff (PSPS) workflow into our operations:

- 1. Assess Daily Fire Weather Index (FWI) from NS NRR:**
 - FWI in Extreme Rating: Proceed to next step.
 - FWI below Extreme Rating: No shutoff required.
- 2. Compare Risk Profiles for Distribution Feeders:**
 - High-Risk Feeders: Proceed to next step.
 - Low-Risk Feeders: No shutoff required.

3. Compare Wildfire Risk Mapping:

- Area Flagged for Higher Risk: Proceed to next step.
- Area Not Flagged for Higher Risk: No shutoff required.

4. Consider Additional Applicable Factors:

- Weather Conditions: High winds, dry conditions, or other adverse weather.
- Community Impact: Assess potential impact on critical infrastructure and vulnerable populations.

5. Community Engagement:

- Communicate potential shutoffs with stakeholders and the community, especially vulnerable populations. Provide advanced warnings to minimize the impact of shutoff.

6. Decision Point:

- All Criteria Met: Deploy proactive safety power shutoff.
- Any Criteria Not Met: No shutoff required.

7. Post-Event Analysis:

- Conduct post-event validation and analysis with NS Power and emergency responder personnel to assess the effectiveness of shutoffs.
- Incorporate improvements and refinements of the decision-making process and execution to improve future response.

Additional consultation with stakeholders is necessary before this PSPS protocol is considered finalized.

7.0 Vegetation Management

NS Power’s electrical system is made up of over 32,000 km of power lines—the majority of which run along forested areas and tree lined roads. Each year, the Company’s vegetation management team identifies work areas throughout the province. Our crews and contractors manage right-of-way paths to ensure power lines are clear of trees and bushes. In 2023, we invested approximately \$32 million in vegetation management and this has increased to \$45 million in 2024 and again in 2025.⁷

NS Power uses a combination of methods to trim and prevent trees from growing near power lines. Options in rural areas include manually trimming tree branches and other higher growing vegetation near the power lines, removing trees in the right-of-way and where possible, and applying herbicides on shorter trees and stumps to restrict tree regrowth.

⁷ Five-Year Reliability Plan 2025-2029, Nova Scotia Power, filed December 20, 2024 with NSUARB

The Vegetation Management Program is designed to proactively reduce tree contacts with power lines, which can be an initiating cause for wildfires. By increasing the width of distribution and transmission corridors and executing proactive vegetation control strategies, the program aims to reduce power interruptions, improve system reliability, and mitigate wildfire risks in the following ways:

- **Greater access for crews conducting routine maintenance and/or post-storm repairs:** Wider corridors allow for easier access, enabling quicker response times and reducing the risk of fires spreading due to delayed repairs.
- **Clear rights-of-way allow for easier visual and drone inspections:** Enhanced visibility helps identify potential wildfire hazards, such as dry vegetation and fallen branches, before they cause outages or ignite fires.
- **Fewer power line conductor failures:** By preventing tree contacts, the program reduces the chances of electrical faults that could lead to fire outbreaks.

The program includes the following targeted strategies, explained further below:

- Distribution Corridor Widening with Managed Rights-of-Way,
- Transmission Corridor Widening with Managed Rights-of-Way,
- Establishing New Rights-of-Way (ROW), and
- Trimming and removal of trees around existing power lines.

7.1 Right-of-Way Management

Right-of-way (ROW) management, including widening, is directed by the Forestry team at NS Power. Targeted widening is dependent on the site, but minimums are generally between 18-32 meters for transmission and 6 meters for distribution. The New Distribution ROW program, which created 6 meters of clearance on the forest side of the Distribution Lines, helped inform the decision to pursue this additional ROW width. This increased width will now be applied to ROW that are currently at 3 meters clearance on the forest side of the line.

As tree trimmings and slash can pose a fuel hazard, they are recommended to be removed from rights-of-way. For NS Power, brush resulting from vegetation management activities is broken into smaller pieces to decompose more easily. Forestry's management philosophy is to build sustainable rights-of-way wherever possible that do not require regular cutting or grubbing to achieve necessary clearances.

Hazard Trees

Hazard trees pose a risk to powerlines from branch contact, partial tree, or whole tree failure. The resulting risks include electrical outages, property damage, personal injury, and wildfire ignition. Successful hazard tree evaluation mitigates the risks associated with tree/powerline conflicts. While some trees are beneficial and align with the integrated vegetation management methodology, such as low-growing trees and shrubs that are acceptable to plant in NS Power's rights-of-way, others pose risks. NS Power promotes the Plant the Right Tree in the Right Place program⁸ and regularly discusses this with customers and community leaders. Hazard trees are quantified by collecting points of interest from inspection programs, ensuring proactive management and wildfire risk reduction.

Vegetation inventory system

In 2025 NS Power is advancing a project to further enhance our existing vegetation inventory system, and this initiative will integrate and leverage new and existing vegetation management data for enhanced risk-based decision-making on the transmission and distribution system. It includes conflation of vegetation condition data, including span-level assessment from satellite imagery analysis, with additional condition factors (reliability, asset condition) and asset criticality to enhance NS Power's understanding of system risk. This project will integrate a detailed vegetation condition data set into overall risk profiles to improve NS Power's vegetation management interventions. Key components include integration of condition data into Business Intelligence (BI) tools, such as Tableau, condition score updates based on executed work, and time-series trending of vegetation condition.

7.2 Stakeholder Engagement for Vegetation

NS Power engages with both the Nova Scotia FireSmart and Prevention Committee and the Halifax Wildfire Advisory Committee. These collaborations aim to enhance wildfire risk reduction strategies and ensure effective communication and coordination during wildfire incidents. Through these partnerships, NS Power participates in developing and implementing comprehensive wildfire prevention and mitigation plans. This includes sharing best practices, conducting joint training exercises, and coordinating response efforts during wildfire events. By leveraging the expertise and resources of these committees, NS Power is better equipped to address the challenges posed by wildfires and protect both infrastructure and communities.

7.3 Substation Vegetation Management

During regular substation inspections, any vegetation present is assessed, and Forestry is contacted to intervene as required. Vegetation is cleared 2-3 meters outside of the fence line, and all vegetation within the substation yard is removed to ensure safety and reliability. This proactive approach helps prevent potential fire hazards and maintains clear access for

⁸ Right Tree Program, Nova Scotia Power, 2025. [Tree Trimming - When To Contact Us | Nova Scotia Power](#)

maintenance and emergency response. Additionally, this vegetation management creates a buffer that protects substations from wildfires in the area, ensuring these critical assets are safeguarded.

8.0 General Operational Practices

At NS Power, our wildfire mitigation plans include operational practices that enhance fault detection and system protection. By deploying advanced technologies such as distribution automation systems, current limiting protectors, and improved reclosers and sensors, NS Power can more quickly identify and isolate faults, thereby minimizing the potential for ignitions. Fault indicators and circuit breakers play a crucial role in narrowing down fault locations and de-energizing affected lines to prevent further damage. Additionally, we are prioritizing the installation of intelligent field devices and communication systems to improve situational awareness and expedite response times during wildfire events. These proactive measures not only safeguard our electrical grid but also contribute to the overall resilience and safety of the communities we serve

8.1 Fault Indicators, Circuit Breakers & Reclosers

Automatic Reclosers

NS Power deploys automatic reclosers across its system to interrupt faults of various causes. The settings for these devices are applied to balance both customer reliability (clearing transient faults) and safely isolating permanent faults. Preventing multiple reclosing operations on a permanent fault through judicious application of settings reduces the likelihood of an ignition due to tree contact or equipment failure.

Fault Indicators

Fault indicators are used to detect faults on electric lines and equipment. They may be utilized when automatic reclosing is disabled or if alternative protection settings are applied during times of wildfire risk. Disabling automatic reclosing is not a regular practice for NS Power.

In general, fault indicators help narrow down the search area to determine where a system failure has occurred. This allows for a potentially faster response to the site if an ignition occurs, a greater chance of determining and correcting a fault cause (when not immediately obvious), and improved customer restoration.

For transmission, a small number of fault indicators are installed at some line taps. These indicate which section of the line has a fault should one occur, while circuit breakers will automatically isolate the line to avoid further damage. This allows the fault location to be identified more quickly.

Fault indicators are used at some targeted locations on NS Power's distribution system, but not widely. Due to the higher volume of protection devices present to isolate faults, fault indicators are used less often. They are strategically placed in isolated or difficult-to-access circuits, such as 85S-401 in Northern Cape Breton, to assist in narrowing down fault locations.

Circuit Breakers

Circuit breakers detect short-circuit fault conditions and operate to limit damage to the system. They are used in substations to de-energize the lines if a fault is detected. Reclosers serve a similar role on distribution feeders, de-energizing the line if they detect a fault.

Downline Device Monitoring and Communication

NS Power is expanding the implementation of telecommunications connectivity providing telemetry and controls to intelligent field devices throughout the grid, including Remote Terminal Units (RTU) and communications to distributed protection equipment. This allows for improved awareness of outages, expedited knowledge of fault locations and remote operation capabilities as well as enhanced data allowing for more in-depth asset management activities to increase the resiliency of our electrical power systems against the risk of wildfires

8.2 Smart Meters

NS Power has installed smart meters for the majority of its customers, allowing events and alarms to be automatically sent to the control center. This technology enhances visibility and response at the individual customer level, which is particularly beneficial for isolated locations where customers may be seasonal residents. The smart meter network across Nova Scotia significantly improves the visibility and traceability of faults and outages, enabling faster response times and reducing conditions that may otherwise lead to wildfires. Beyond accurately pinpointing outages, smart meters help mitigate wildfires by identifying specific patterns of line disturbances that indicate fire threats, such as managing vegetation or other obstructions that could cause sparks and lead to fires, and locating energized, downed power lines that could spark fires. They also provide load and voltage data in near real-time, maintaining situational awareness around problem areas or at the sites of mobile substations or generators, and confirm switching operations and verify outage restoration as circuits return to their original configurations.

NS Power is on track to achieve the benefits from AMI for wildfire risk reduction with existing integrations, primarily through the capability of pinging meters to validate power status. There

are opportunities to further integrate AMI data with outage management systems for better visibility to System Operators and to provide a consolidated dataset of outage and AMI data. This consolidated dataset lays the foundation for more advanced performance analysis by Reliability Engineers. Additionally, integrating smart meter alarms and power quality data into outage management systems provides System Operators and Reliability Engineers with additional context on outage events, informing restoration tactics during events and post-event analysis. Smart meters collectively enhance NS Power's ability to detect and respond to potential wildfire risks, thereby safeguarding the electrical grid and contributing to the overall resilience and safety of the communities we serve.

9.0 Emergency Response

The purpose of an emergency response program is to coordinate safe and effective emergency preparedness. The response should extend to safely and efficiently prepare for, respond to, and recover from all threats and hazards, including wildfires.

9.1 Emergency Services Restoration Plan

NS Power has an Emergency Services Restoration Plan (ESRP) that is deployed to co-ordinate restoration response for events that are expected to result in customer outages of longer than 36 hours or 50,000 customers for more than 24 hours. NS Power developed the ESRP and first filed it with the Board on August 13, 2004. The ESRP is reviewed annually by NS Power and any changes or learnings from storms or drills are filed with the NSUARB for approval.

The plan includes strategies for the allocation and deployment of resources, including personnel, equipment, and materials, to support restoration efforts during emergencies. The ESRP emphasizes the importance of communication and coordination with federal, provincial, and local fire authorities, as well as other emergency response organizations, to ensure a unified and effective response. The plan incorporates safety protocols to protect both the public and NS Power employees during emergency response and restoration activities. In the event of a wildfire(s) impacting a large volume of NS Power's system and/or customers, the ESRP would be activated to support the restoration plans in response to the wildfire(s).

9.2 Cooperation with Suppression Agencies

Coordination with federal, provincial, and local fire authorities to support the planning and operations of firefighting in real-time, including information-sharing, dispatch of resources, and dedicated staff.

NS Power's Energy Control Centre (ECC) has a standard operating procedure to call upon during a wildfire response situation in relation to the potential for transmission impacts. The ECC

coordinates directly with Nova Scotia Department of Natural Resources and Renewables and with relevant emergency response organizations (NS EMO, local firefighters, police, etc.), as required.

Flame suppression products that fire authorities use could cause issues with electrical equipment. It has been regularly communicated to authorities that water bombers should avoid hitting overhead equipment directly with water as it can cause further damage. Salt water is discouraged to be used around energized equipment due to the increased potential for flashover. For ground-based firefighting, there are recommended minimum separation distances for people and conductive materials to power lines. These are summarized in Table 9. Any water from a fire hose would be included in these recommendations.

Table 9. Normal Limits of Approach for unqualified persons and conductive materials

NSPI Nominal Circuit Voltage (Phase to Phase)	CSA Voltage Range (Phase to Ground)	Limit of Approach (Metres)	Limit of Approach (Feet)
0.75 – 25 kV	0.4 – 18 kV	3.0	10
40 kV	18 – 22 kV	3.0	10
69 kV	22 – 50 kV	3.0	10
138 kV	50 – 90 kV	5.0	16.5
230 kV	120 – 150 kV	6.1	20
345 kV	190 – 220 kV	6.1	20

9.3 Materials Management

As part of NS Power's comprehensive wildfire mitigation strategy, the Transmission and Substation Reliability Teams are committed to regularly reviewing existing critical spare equipment. This ongoing assessment aims to identify additional spare equipment requirements for emergency response and determine optimal storage locations. Incorporating the availability of spares to address potential losses in areas with higher fire risk is a key recommendation for enhancing our preparedness.

For distribution equipment, which often consists of standard parts applicable to most sites, NS Power regularly reviews the minimum and maximum quantities and updates necessary quantities as needed. This proactive approach ensures that on-hand quantities are increased as required, enhancing readiness and resilience for wildfires.

NS Power's emergency services response plan, established in 2004, has been rigorously tested through several severely damaging storms, including Hurricane Dorian in 2019 and Fiona in 2022. During these events, NS Power successfully maintained a critical supply of distribution equipment, facilitating timely repairs and restoration for our customers. The same levels of equipment are available to support wildfire response efforts, ensuring that distribution equipment impacted by wildfires can be swiftly repaired and restored.

Safety Communication: Afterglow on CCA Poles

NS Power primarily utilizes wood poles treated with Chromated Copper Arsenate (CCA) for new installations. These poles have a characteristic known as Afterglow, where the heavy metal preservative enhances heat transfer into the pole's interior, causing the temperature to increase. When a CCA-treated pole fire is extinguished, the heat energy transfers back to the surface, potentially causing re-ignition. Fires in CCA poles are often due to insulation failure on attachments, and even after extinguishing, the pole could re-ignite up to 2 hours later. Poles treated with oil-borne preservatives, like Penta-Chlorophenyl (PCP), develop outer char that insulates interior wood and self-extinguishes, limiting damage.

Caution is necessary when handling CCA-treated poles exposed to wildfire conditions. Workers must protect themselves from hot surfaces and possible re-ignition. Poles or pole pieces above grade, extinguished for more than 3 hours, are less likely to re-ignite. All pole butts (below grade) must be fully removed due to retained heat. Employees should check for heat before removal.

Precautions for Removing CCA-Treated Pole Butts from Wildfire Areas:

1. Expect re-ignition when the pole butt is exposed to oxygen. Have fire extinguishers or a water hose/supply ready.
2. Always wear leather gloves free from oil or other combustibles, cracks, or holes.
3. Avoid contact between the pole piece and any other part of the body.
4. Remove pole pieces from the site in a metal container or trailer. Do not leave them on the ground in the right of way.

10.0 Resources for Wildfire Prevention and Mitigation Best Practices

NS Power continues to engage with electric utilities and other stakeholders to ensure its proactive approach to wildfire risk management is aligned and/or leading industry practices. NS Power is engaged with Electricity Canada's Climate Change Adaptation Committee where wildfire-related work is discussed and shared with other Canadian utilities. NS Power is also working with Electricity Canada's Best Practices Transmission Committee (BPTC), who have been drafting the Utilities Wildfire Mitigation Best Management Practices Guide. In addition, NS Power is a member of several groups with the Centre for Energy Advancement Through Technological

Innovation (CEATI), such as the Asset Management in Generation (AMIG), Overhead Transmission Equipment (OTE) group and the Vegetation Management group that discuss and collaborate on various climate adaptation best practices, such as wildfire mitigation plans. CEATI has representation from utilities across North America and internationally. NS Power also contributes to the development of standards through the Canadian Standards Association (CSA) which is incorporating climate risk into its standards, including those which guide distribution system design.

From the Electricity Canada (formerly CEA) guidelines, it is advised for utilities to develop a comprehensive Wildfire Prevention, Preparedness, and Response plan that incorporates best practices. The best practices that were reviewed include: the CEA Wildfire Mitigation Guide⁹, the BPA 2021 Wildfire Mitigation Plan¹⁰ and the SDG&E 2020-2022 Wildfire Mitigation Plan.¹¹ NS Power also engages with other member utilities of the EEI and had participated in Wildfire Mitigation Summits with PG&E.

⁹ CEA, 'Utility Wildfire Mitigation Guide', <https://electricity.ca/wp-content/uploads/2020/05/WildfireMitigationGuide.pdf>, 2020

¹⁰ Bonneville Power Administration, 'BPA 2021 Wildfire Mitigation Plan', <https://www.bpa.gov/news/pubs/GeneralPublications/BPA-Wildfire-Mitigation-Plan.pdf>, 2021

¹¹ San Diego Gas & Electric Company, '2020-2022 Wildfire Mitigation Plan Update', [Microsoft Word - SDGE 2021 WMP Update DRAFTv2](#), 2021

APPENDIX 5A
2026-2027 FUEL AND PURCHASED POWER

REDACTED

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1 INTRODUCTION

The two-year test period includes fuel data for 2026-2027. The following is a more detailed explanation about the sources of fuel and purchased power, the fuels forecast for 2026-2027, the Maritime Link, and the hedging plan.

1.1 GENERATION BY FUEL TYPE

Nova Scotia Power has 2,422 MW of generating capacity. Coal and petcoke-fired plants account for 51 percent of this capacity, while natural gas and oil-fired plants make up 28 percent. Hydro, wind, and biomass provide the remaining 21 percent. Government policy and legislative changes have resulted in a requirement for NS Power to deliver 40 percent of its sales from renewable sources every year between 2025 and 2029, increasing to 80 percent by 2030.

NS Power's current generation fleet capacity and fuel type requirements are set out below in **Figure 1**.

Figure 1 – Generation Fleet Capacity and Fuel Type

Plant	Max Net Capacity	Year Unit in Service	Fuel Type
Lingan Unit 1	153	1979	Coal / Petcoke
Lingan Unit 2	148	1980	Coal / Petcoke
Lingan Unit 3	153	1983	Coal / Petcoke
Lingan Unit 4	153	1984	Coal / Petcoke
Tufts Cove Unit 1	78	1965	Natural Gas
Tufts Cove Unit 2	93	1972	Oil/Natural Gas
Tufts Cove Unit 3	147	1976	Oil/Natural Gas
Tufts Cove Unit 4 (LM 6000)	49	2003	Natural Gas

Plant	Max Net Capacity	Year Unit in Service	Fuel Type
Tufts Cove Unit 5 (LM 6000)	49	2005	Natural Gas
Tufts Cove Unit 6 (LM 6000)	46	2012	Natural Gas
Point Tupper	150	1973	Coal / Petcoke
Point Aconi	168	1994	Petcoke / Coal
Trenton Unit 5	150	1969	Coal / Petcoke
Trenton Unit 6	154	1991	Coal / Petcoke
Port Hawkesbury Biomass	43	2013	Biomass
Burnside 1	33	1976	Light Fuel Oil
Burnside 2	33	1976	Light Fuel Oil
Burnside 3	33	1976	Light Fuel Oil
Burnside 4	33	1976	Light Fuel Oil
Victoria Junction 1	33	1976	Light Fuel Oil
Victoria Junction 2	33	1975	Light Fuel Oil
Tusket 1	33	1971	Light Fuel Oil
NS Power Wind	81	N/A	N/A
NS Power Hydro	374	N/A	N/A
NS Power Solar	2	2022	N/A

In addition to these sources of generation, NS Power has rights to 153 MW of Maritime Link Capacity, representing Newfoundland and Labrador Hydro's Nova Scotia Block delivery obligations. Over the course of the test period, NS Power anticipates adding 150 MW of utility-scale battery storage (100 MW in 2025 and 50 MW in 2026). These assets will allow the utility to achieve a more economic dispatch of the generation resources listed in Figure 1.

Figure 2, Figure 3 and Figure 4 below provide a breakdown of generation by type for 2025, 2026 and 2027 respectively.

Figure 2 – 2025 Generation by Type

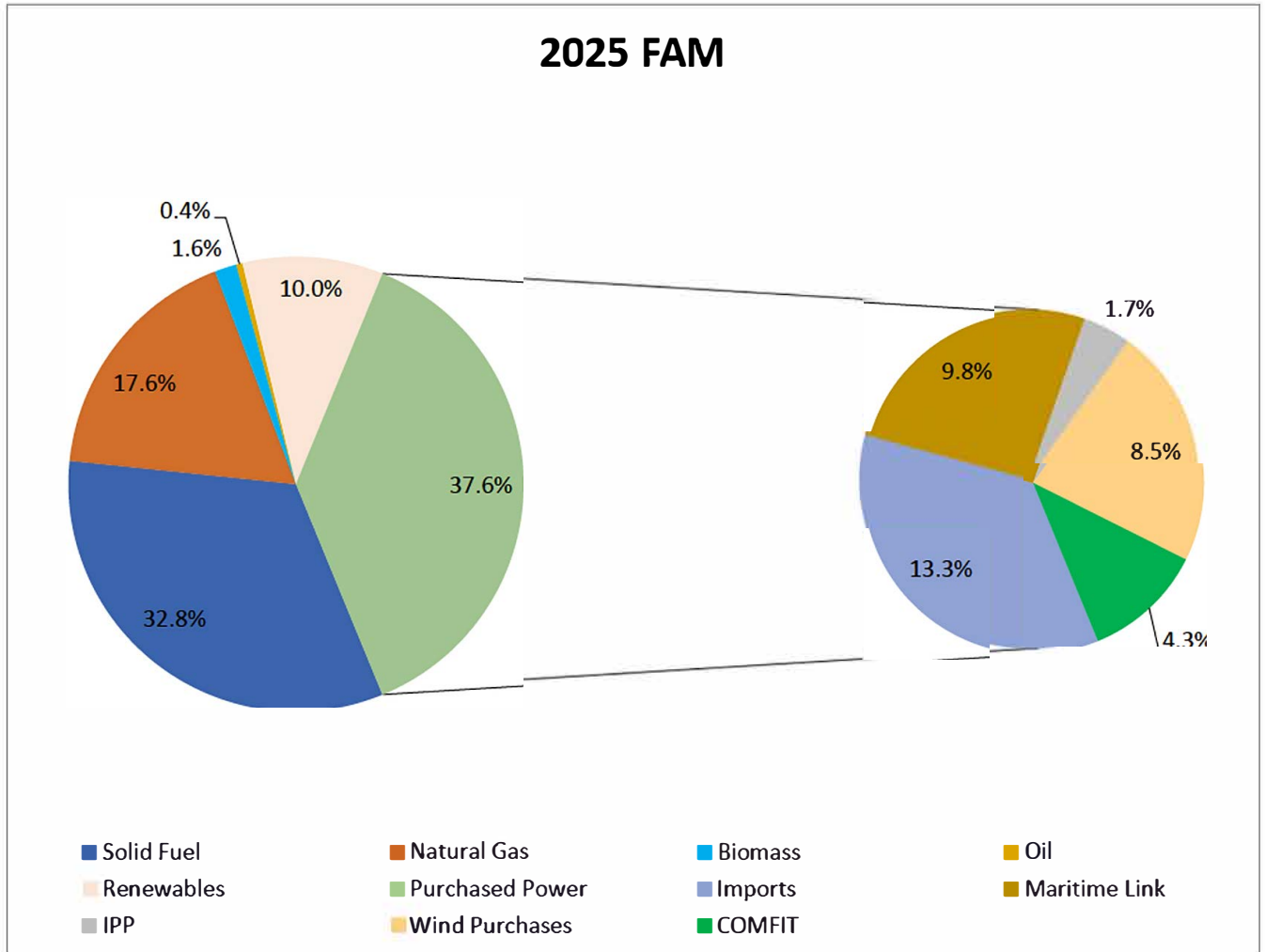


Figure 3 – 2026 Generation by Type

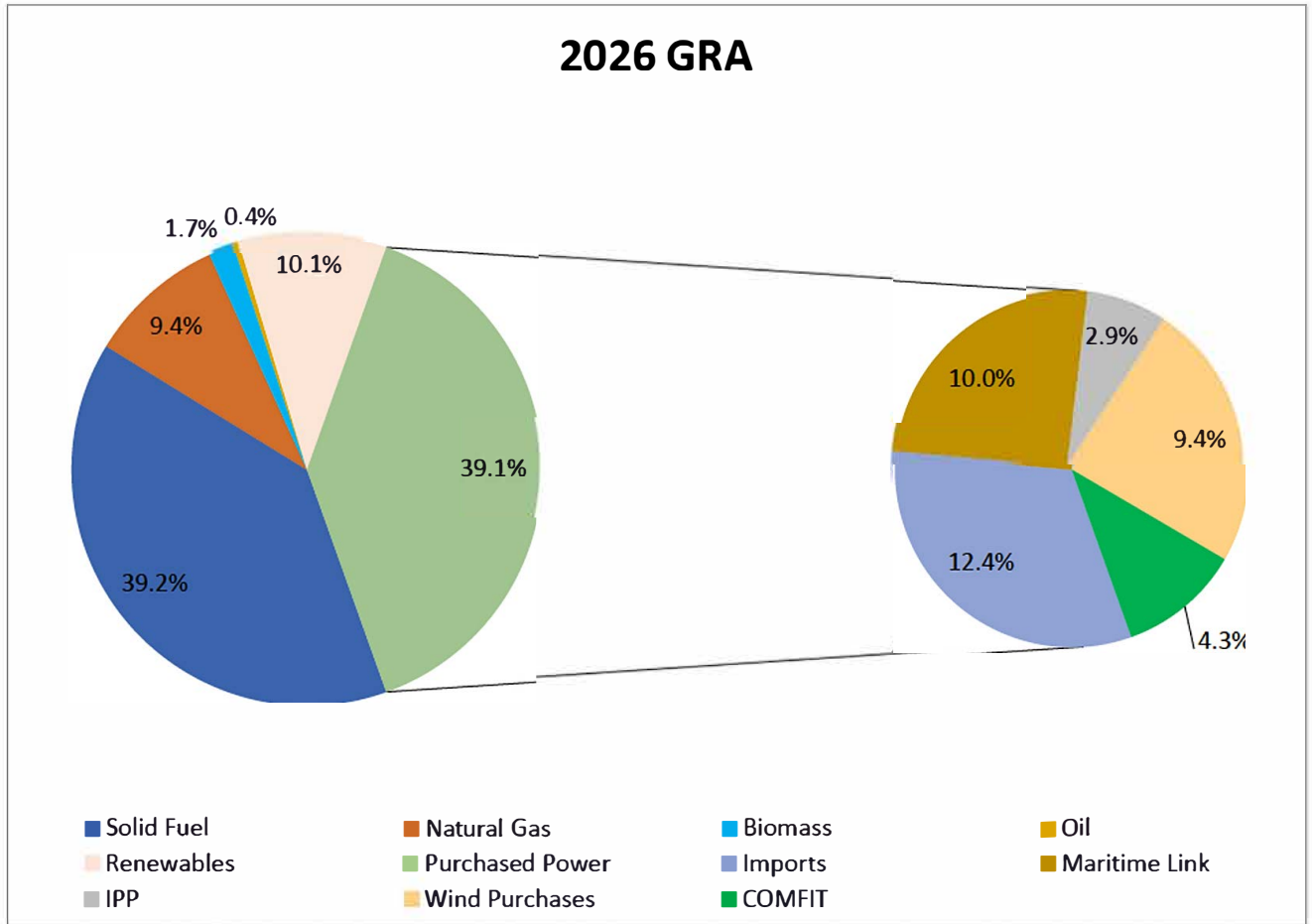
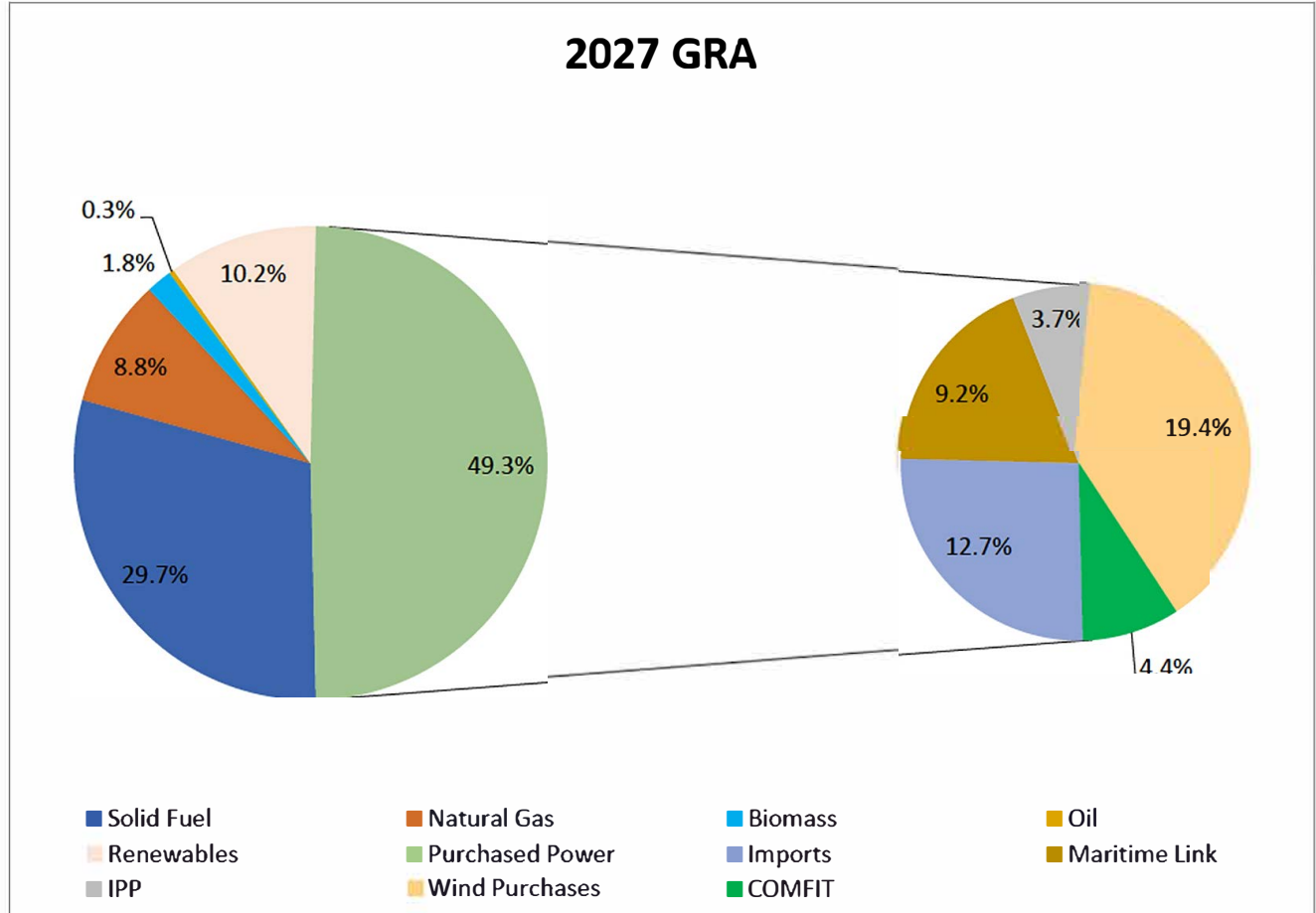


Figure 4 – 2027 Generation by Type



1.1.1 Solid Fuel

Although NS Power's reliance on thermal generation continues to decrease and the Nova Scotia Government's legislated¹ goal to phase out coal-fired electricity generation by 2030, solid fuel continues to comprise a significant portion of NS Power's forecast fuel requirements. NS Power takes a portfolio approach to its solid fuel procurement and contracts all supply from foreign suppliers. The Company also uses financial hedges to mitigate exposure to market prices. Further details are set out in **Sections 1.2.2 and 1.4** below.

¹ *Environmental Goals and Climate Change Reduction Act*, S.N.S. 2021, c. 20, s. 7(m).

1.1.2 Natural Gas

NS Power forecasts a reduction in natural gas consumption over the GRA period as new renewable projects come online. Natural gas remains an important part of the generation mix as it emits fewer greenhouse gases and other emissions than coal, is competitively priced, and provides flexibility for NS Power's capacity requirements, particularly for fast-acting generation. The Company has taken advantage of long-term pipeline contracts in order to secure the best value for customers. Further details are set out in **Section 1.2.5**

1.1.3 Oil

NS Power does not use heavy fuel oil (HFO) as a primary fuel to generate electricity due to its high cost relative to natural gas or solid fuels. However, HFO is used as a back-up fuel in two of the three steam units at Tufts Cove as a hedge against gas price escalation and supply availability. HFO is also used as a start-up fuel in most of the coal-fired plants, and accounts for less than one percent of NS Power's generation. Light fuel oil (LFO) is primarily used in the combustion turbine fleet and as start-up fuel for Point Aconi. Forecast and contract information for HFO is set out in **Section 1.2.6** below and information about LFO is set out in **Section 1.2.7** below.

1.1.4 Renewable Energy

NS Power continues to increase its renewable energy generation from wind, hydro, biomass, and solar. In addition to generating renewable energy from its own sources, NS Power will purchase renewable energy from independent power producers (IPPs) and community groups (COMFIT) across the province. NS Power obtains its biomass generation from the Port Hawkesbury Biomass plant, as well as from purchases from Brooklyn Energy. Further detail on NS Power's renewable energy portfolio is provided in **Section 1.2.8** below.

1.2 FUELS FORECAST

1.2.1 GRA Period Snapshot

Fuel costs are comprised of the delivered cost of solid fuels, natural gas, oil, and purchased power. The annual 2026-2027 GRA BCF is forecast to decrease from \$1,039.1 million in the 2025 FAM Budget to an average of \$918.5 million, with total costs amounting to \$1.8 billion over the two-year 2026-2027 GRA Period.

In recent years, forecasted cost drivers have been associated with legislated environmental requirements, such as reduced emissions, the achievement of the 40 percent renewable requirement, and general decline of reliance on fossil fuels in pursuit of decarbonization. For the GRA Period, NS Power has received emission limit relief to assist with cost control while large-scale renewable projects are being constructed. This results in an increase in generation from solid fuel in 2026 which is forecasted to be economical compared to natural gas and oil. However, there will be an overall decline in thermal generation in 2027 as renewable energy projects begin to come online and become economically role in aiding the decarbonization of the energy grid and increasing the delivery of cleaner energy to Nova Scotians.

NS Power incurs a significant portion of its fuel for generation and power import costs in US Dollars (USD). Over the 2026-2027 GRA Period, USD transactions are forecasted to total \$ [REDACTED] million at an average foreign exchange (FX) rate of [REDACTED]. NS Power has financial hedges covering \$ [REDACTED] million USD at an average FX rate of [REDACTED] over the same period.

The Nova Scotia Output-Based Pricing System (OBPS) was introduced on January 1, 2023, as a carbon pricing mechanism designed to regulate greenhouse gas emissions from large industrial emitters and electricity generators. NS Power's Lingan, Point Aconi, Point Tupper, Trenton, Tuft's Cove, Port Hawkesbury Biomass, and Burnside generating stations are registered under the program and must report annual emissions to determine Compliance Obligation costs. For the GRA Period, Compliance costs are forecast to be \$5.7 million in 2026 and \$14.6 million in 2027.

As illustrated in **Figure 5**, the forecast cost of fuel increases from \$83.69/MWh in 2024 GRA Refresh to \$90.03/MWh in 2025, before decreasing to \$80.64/MWh in 2026, and then increasing slightly to \$81.19/MWh in 2027.

favourable compared to emitting-generation sources.

The Maritime Link will be integral to the Nova Scotia grid over the GRA Period by increasing system reliability and security, as well as assisting NS Power in meeting the RES requirement of supplying 40 percent of annual sales from renewable sources. NS Power forecasts the delivery of [REDACTED] GWh of NS Block energy and [REDACTED] GWh of Energy Access Agreement (EAA) purchases at a cost of \$[REDACTED] million over the 2026-2027 GRA Period. The assessment cost of the Maritime Link is forecasted to be \$[REDACTED] million in 2026 and \$[REDACTED] million in 2027, which includes approximately \$41 million per year in costs related to the \$500 million Federal Loan Guarantee received by NSP Maritime Link Incorporated and paid to NS Power.

Wind generation from Independent Power Producers (IPPs) is expected to increase significantly in 2026 and 2027 due to the completion of large-scale wind farms. Excluding COMFIT Projects, the installed capacity from Wind IPP projects is forecasted to increase from 354 MW in 2025 to 484 MW in 2026, and then to 797 MW in 2027. The addition of these wind farms will play a key

Figure 5 – 2024-2027 NS Power Fuel and Purchased Power Costs Per MWh

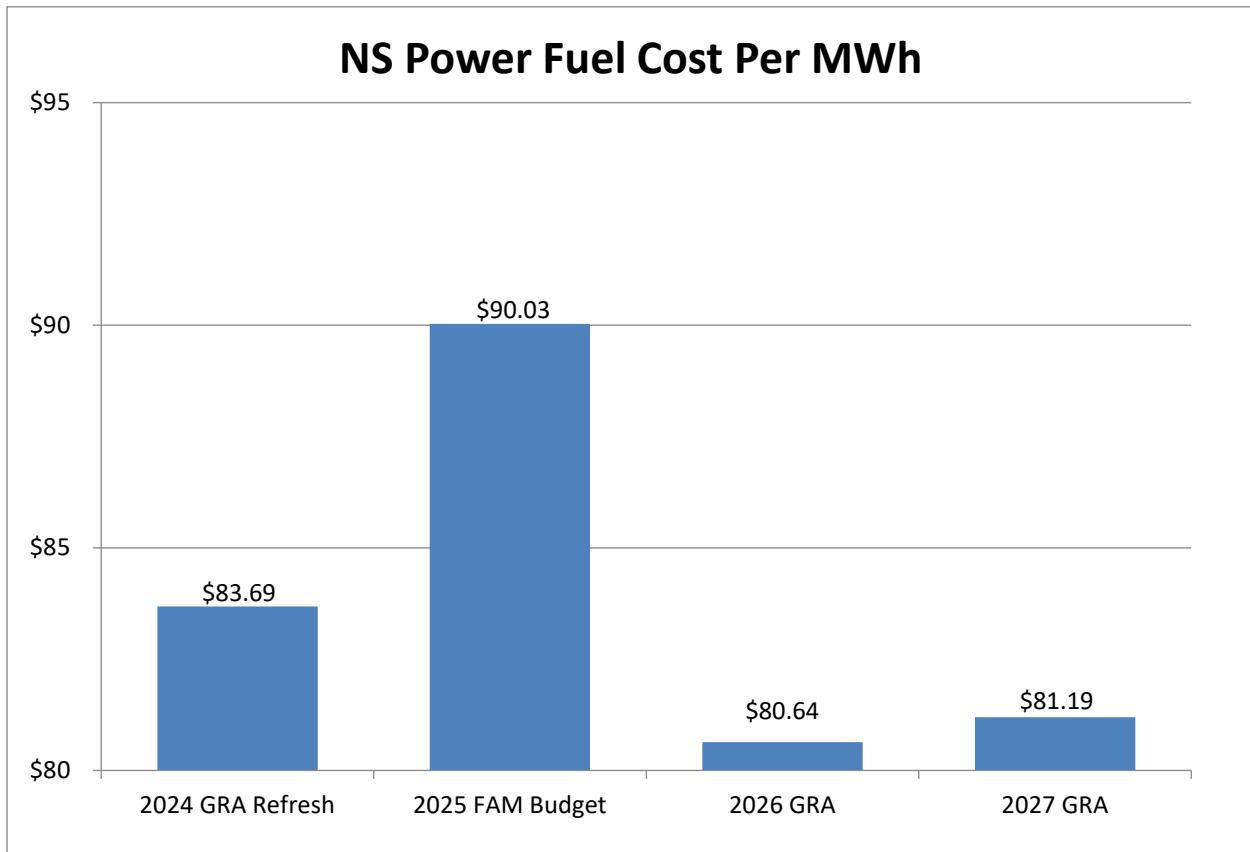
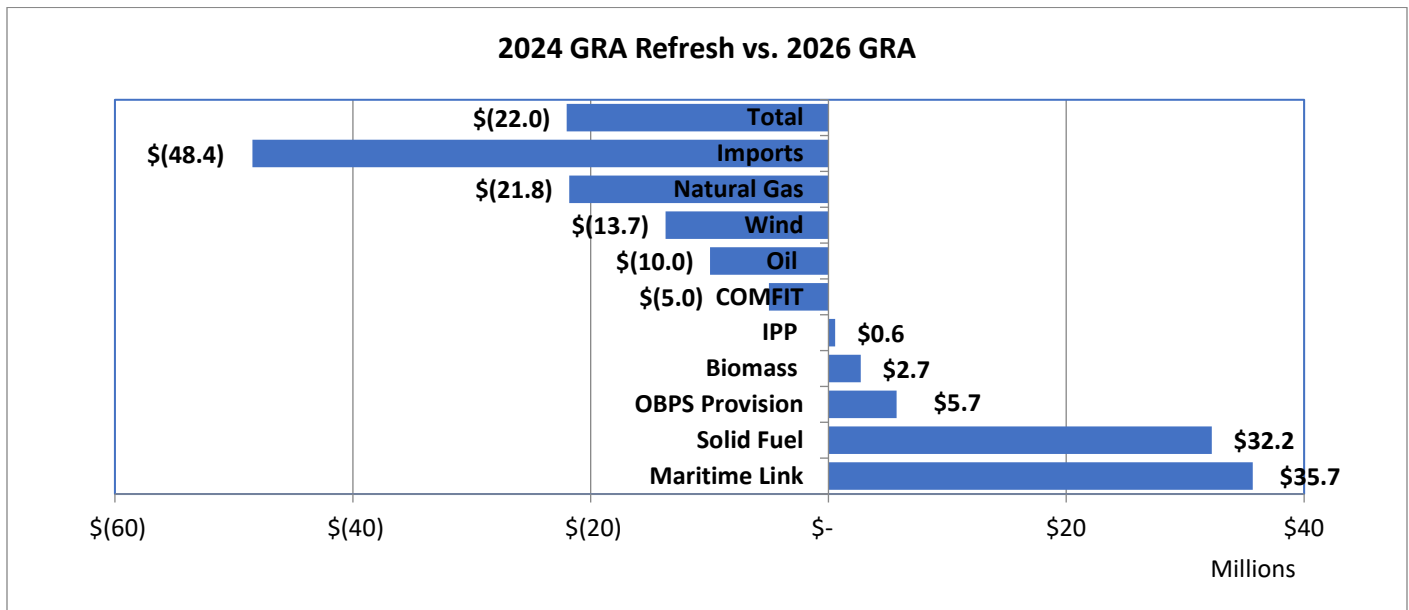


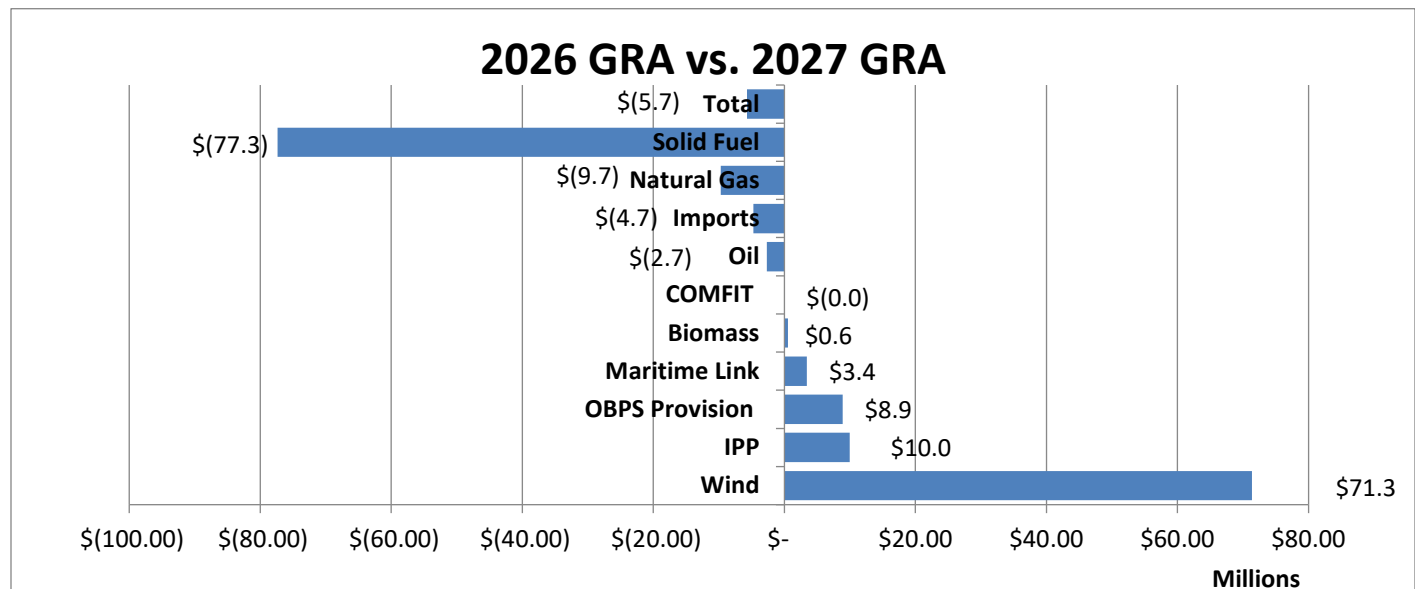
Figure 6 – 2026 BCF Component Cost Changes vs 2024 GRA Refresh



As shown above in **Figure 6**, there is a total fuel cost decrease of \$22 million in the 2026 GRA compared to the 2024 GRA Refresh. The largest drivers of the decline compared to the 2024 GRA

Refresh is a \$48.4 million decrease in imported power costs and a \$21.8 million decrease in natural gas costs, primarily due to increased forecasted generation from solid fuel. These were partially offset by increased Maritime Link assessment costs which increased by \$35.7 million to include the annual repayment of a 28-year, \$500 million Federal Loan Guarantee received by Nova Scotia Power Maritime Link Inc. and paid to NS Power, as well as increased solid fuel generation.

Figure 7 – 2027 BCF Component Cost Changes vs 2026 BCF



As shown above in **Figure 7**, total fuel costs are expected to decrease by \$5.7 million in the 2027 GRA forecast compared to 2026. The primary reason for the decrease is a significant increase in IPP Wind generation expected to begin in 2027 which has favourable pricing compared to thermal generation and will result in decreased generation from all thermal sources.

Figure 8 below shows the comparison of the cost of fuel and purchased power per MWh by source for the years 2024 to 2027.

Figure 8 – CONFIDENTIAL 2024-2027 Comparison of Cost of Fuel/MWh

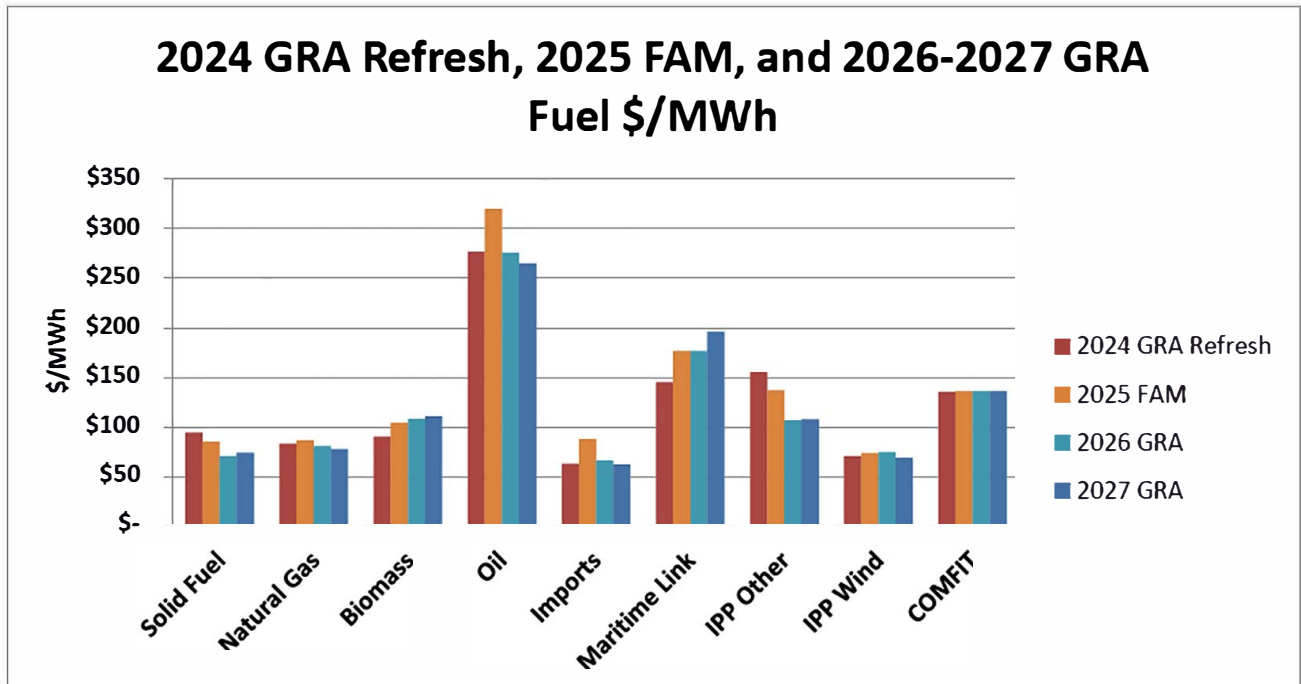
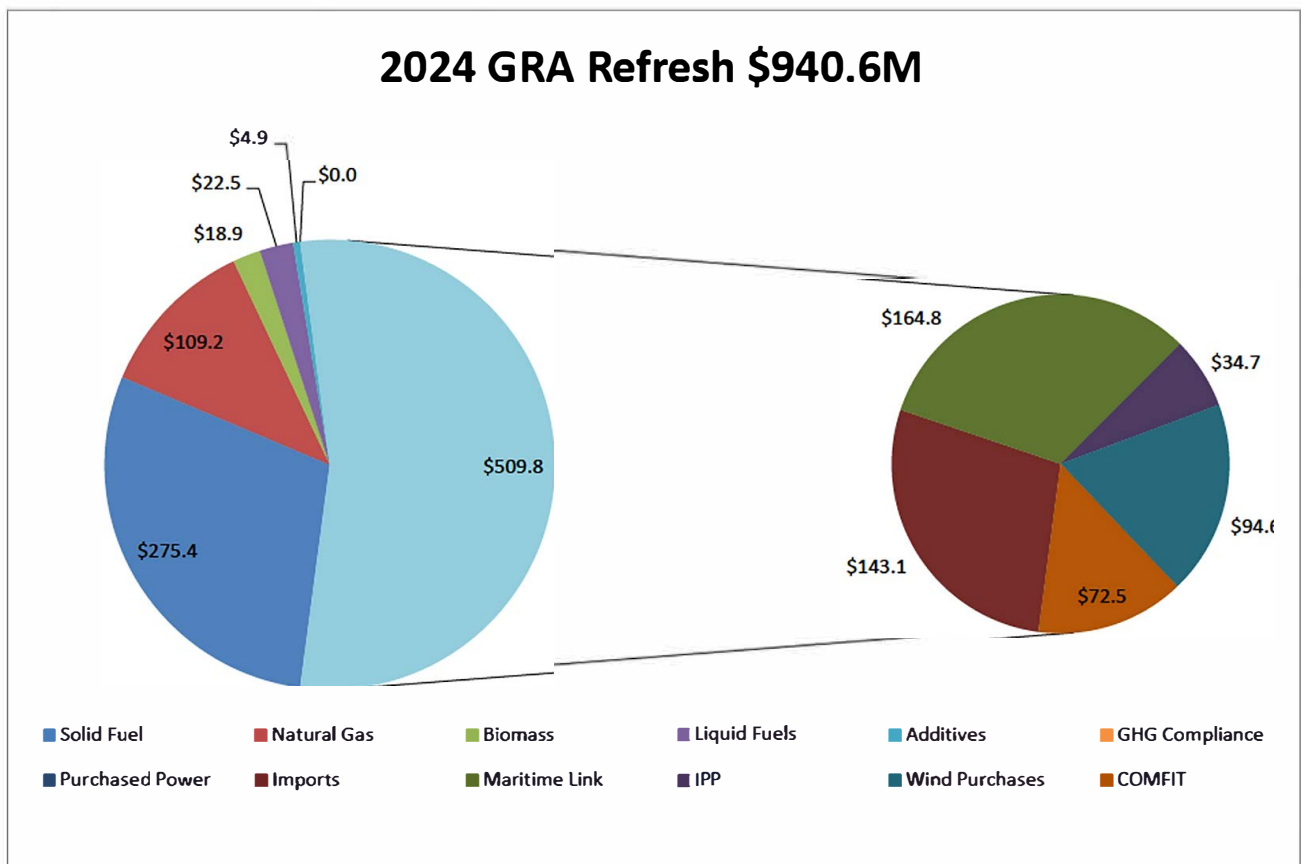
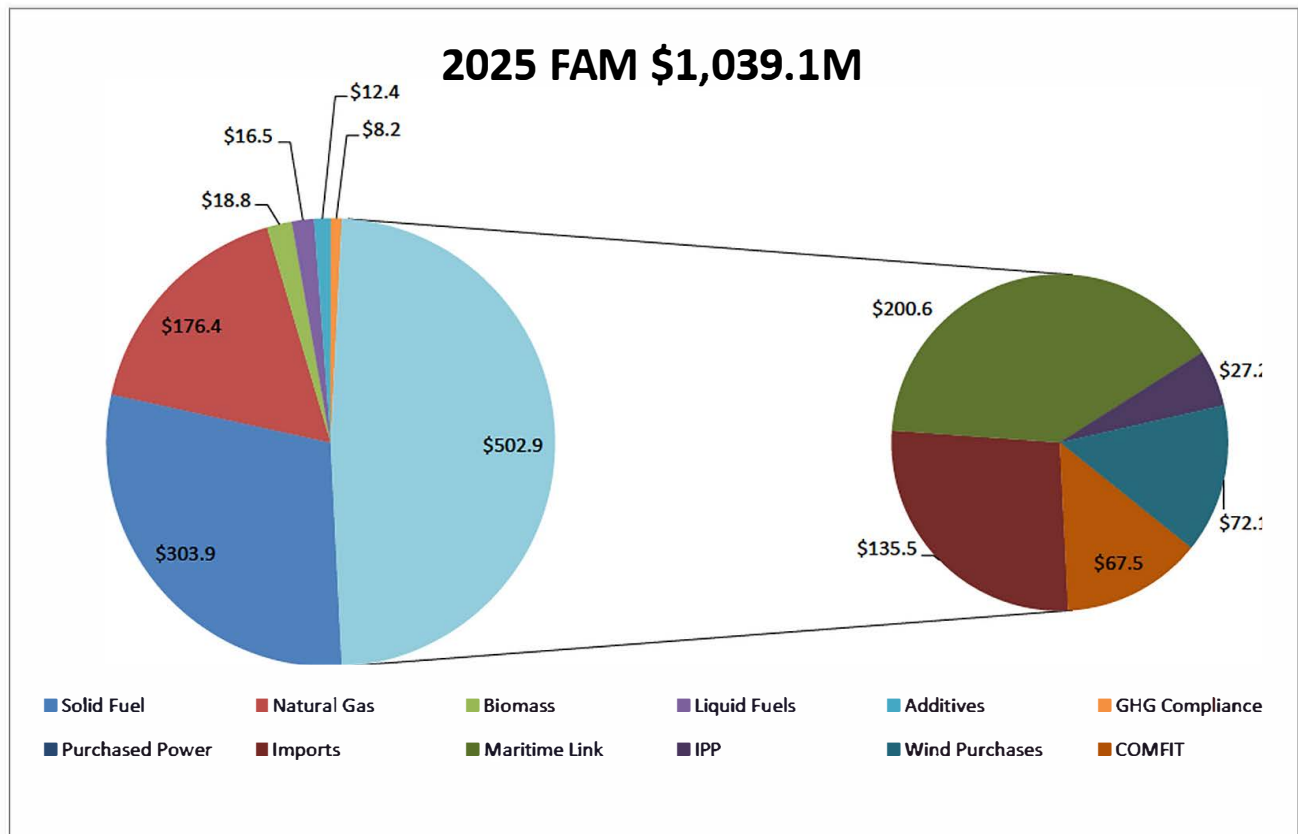


Figure 9 – 2024 Breakdown of BCF by Fuel and Purchased Power Type

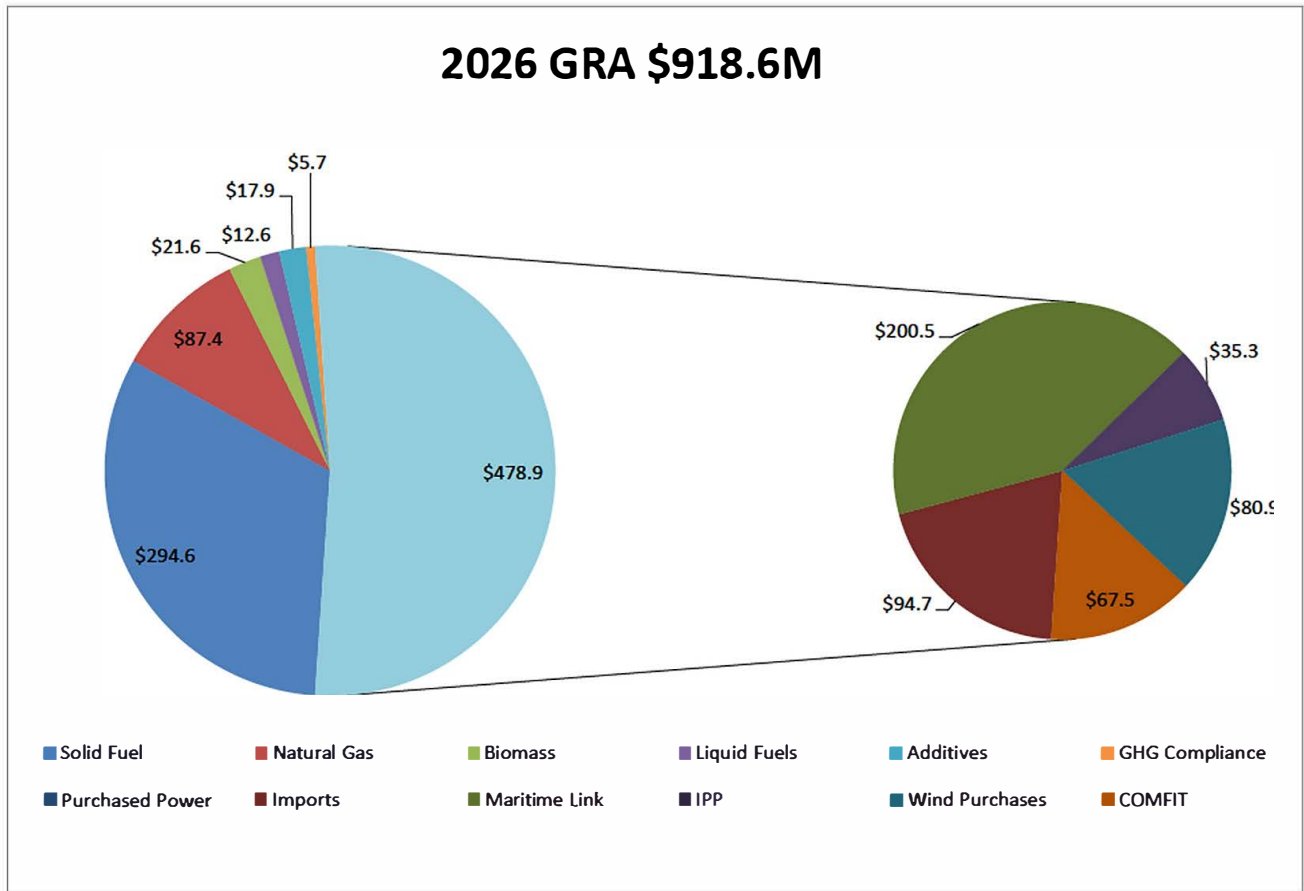


1 **Figure 10 – 2025 Breakdown of BCF by Fuel and Purchased Power Type**



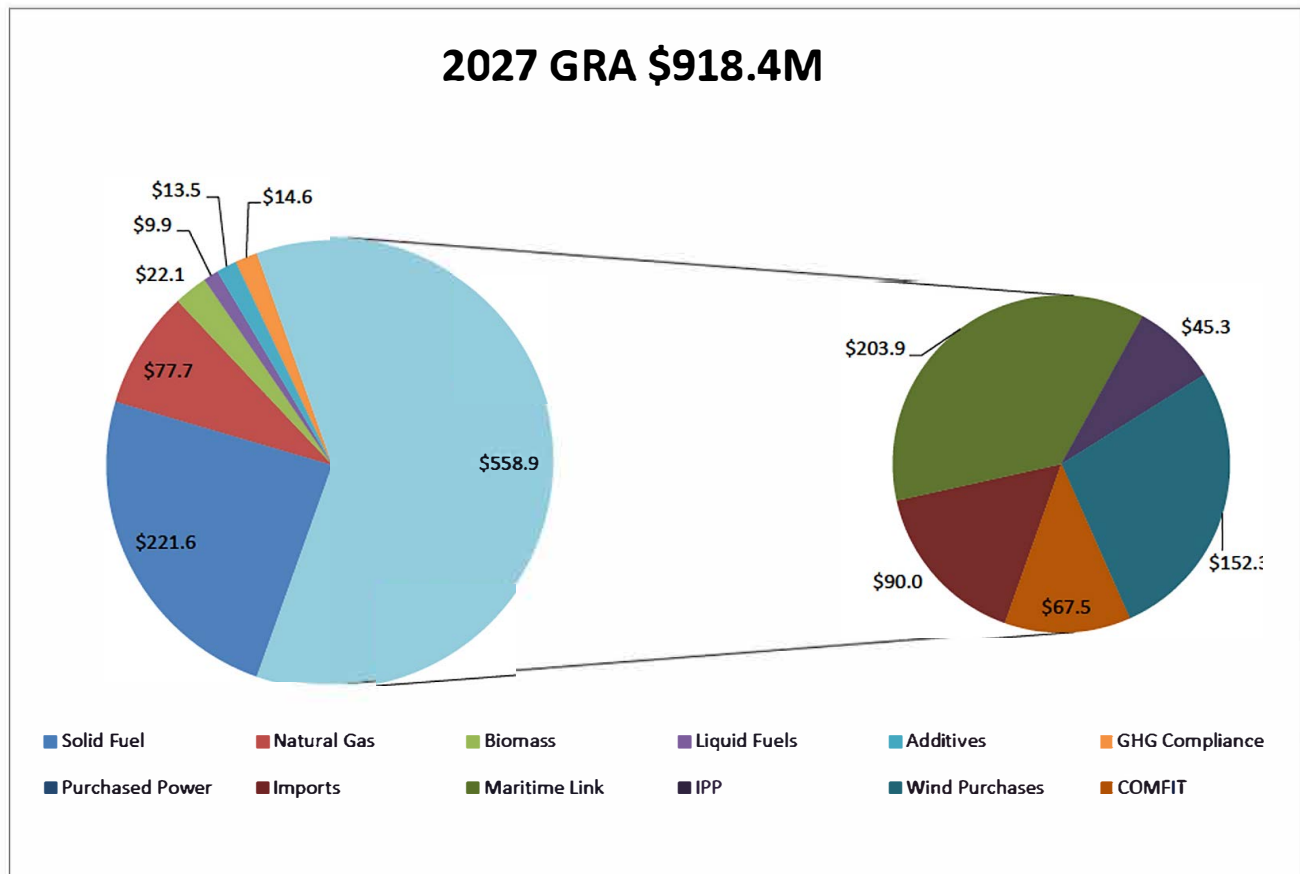
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1 **Figure 11 – 2026 Breakdown of BCF by Fuel and Purchased Power Type**



2
3

Figure 12 – 2027 Breakdown of BCF by Fuel and Purchased Power Type



The following sections provide details on NS Power’s 2026-2027 fuel requirements compared to the 2024 GRA Refresh. All commodities purchased in USD have been converted to Canadian Dollars (CAD) at NS Power’s forecast blended achieved exchange rate of [REDACTED] for each USD in 2026, and [REDACTED] in 2027. The derivation of this exchange rate is described in **Section 1.2.11** of this Application.

1.2.2 Solid Fuel Portfolio

In accordance with its Fuel Manual, NS Power procures and manages a reliable and competitively priced supply of fuel on a system-wide evaluated cost basis for its generation fleet, consistent with regulatory and environmental requirements. The fuel and power procurement policy incorporates a portfolio approach to procurement. Standardized Filing Appendices A OE-01E and OE-01J provide detailed information on the composition of the solid fuel portfolio.

Hedging of solid fuel positions will be based on the Company's Fuel Hedging Plan referred to below in **Section 1.4** and set out in the NS Power Fuel Manual and included in Standard Filing Appendix A OE-01J. The Fuel Hedging Plan is detailed in **Section 1.4** below and builds upon the success of the 2020-2022 Hedging Plan with slight modifications. For price stability, there are times when NS Power enters into financial hedges in advance of physical purchases. Financial hedges in place for the 2025-2027 GRA Period are shown as a percentage of total requirements in Standard Filing **OE-01J**.

Physical fuel requirements are determined by the Portfolio Optimization team using PLEXOS dispatch optimization software. NS Power reviews its contracted physical commitments on an ongoing basis, while monitoring its requirements and changes in market conditions to ensure the fuel portfolio is optimized to produce the lowest overall cost while meeting environmental requirements. Forecast volumetric requirements change over time, and minimum expected volumes are used to guide targets for hedging using physical purchases. In addition to physical contracts, financial coal hedges have been executed for [REDACTED] tonnes for 2025, [REDACTED] tonnes for 2026, and [REDACTED] tonnes have been financially hedged for 2027 as of the forecast date (Mar 31, 2025). Please refer to Confidential 13 below.

Figure 13 – CONFIDENTIAL 2024-2027 Comparative Physical Solid Fuel Portfolio

20

NS Power Solid Fuel Portfolio Table				
(in thousands of metric tonnes)				
YEAR	2024 Actuals	2025 Forecast	2026	2027
Contracted	[REDACTED]			
Open				
Total				
Physical Contracted percentage				
Open Physical percentage				

1.2.3 Long-Term Contracts

Long-term contracts are contracts which have a duration of four years or more.

NS Power [REDACTED] for solid fuel within the 2026-2027 GRA Period for which the contract term spans four years or more as set out in Confidential 14.

Figure 14 – CONFIDENTIAL 2026-2027 Long-Term Solid Fuel Contracts

Supplier	Solid Fuel Type	Contract Start Date	Contract Expiry
[REDACTED]			

1.2.3.1 Medium-Term Contracts

Medium-term contracts are defined as contracts with duration of one to three years.

NS Power [REDACTED] for solid fuel within the 2026-2027 GRA Period for which the term spans one to three years as set out in **Figure 15**. Volumes associated with these contracts are shown in **OE-01E**.

Figure 15 – CONFIDENTIAL 2022-2024 Medium-Term Solid Fuel Contracts

Supplier	Solid Fuel Type	Contract Start Date	Contract Expiry
[REDACTED]			

1.2.3.2 Short-Term Contracts

The balance of NS Power's solid fuel requirements is purchased on a short-term basis. This amount varies based on overall consumption and contractual volume options.

1.2.3.3 Transportation Contracts

NS Power receives solid fuel at two port facilities. Both the International Pier (INP), located in Sydney and the Point Tupper Marine Terminal (PTMT) located in Point Tupper receive self-unloading vessels that typically originate from the eastern seaboard of North America and South America. PTMT can also handle bulkier vessels.

NS Power purchases most coal on a free-on-board load port basis and is therefore responsible for the procurement of ocean freight. This provides transportation price stability along with flexibility and optimization of delivery schedules. Petroleum coke purchases are often made on an as-delivered basis with the supplier responsible for freight.

The type of freight NS Power uses depends primarily on economics but, as noted above, deliveries to the INP are currently limited to self-unloaders. PTMT can accommodate most vessel types.

NS Power has a five-year contract with [REDACTED] for marine freight services from 2021 to 2025. NS Power's annual volume optionality in this five-year contract is as follows: [REDACTED]

[REDACTED] This is in line with the anticipated trajectory of renewables offsetting coal generation over this timeframe.

In developing the solid fuel figures for this Application, NS Power followed the fuel forecast methodology outlined in Appendix B of the FAM POA.

Solid fuel is used at four generating facilities: Langan, Point Aconi, Point Tupper and Trenton. Most of the coal and all the petroleum coke consumed at these stations is imported. NS Power purchases domestic coal if it is available, meets environmental requirements, and is competitively priced.

Confidential **Figure 16** compares the forecast mix of solid fuels from the Company's 2025-2027 GRA to the mix in the 2024 BCF Compliance Filing.²

Figure 16 – CONFIDENTIAL 2021-2024 BCF Solid Fuel Mix (Percentage)

Solid Fuel Type	2024 Actuals	2025 Forecast	2026	2027
Low-Sulphur (<1.1% Sulphur)				
Mid-Sulphur (<3.5% Sulphur)				
Domestic				
Petcoke				
Total				

While NS Power will continue to utilize a mix of lower sulphur and higher sulphur solid fuels through the 2026-2027 GRA Period, coal utilization continues to be further offset by increased renewables.

1.2.4 Environmental Compliance

NS Power is required to manage air emissions within annual limits set by regulation. The air emission compliance limits specified in the Air Quality Regulations³ were amended November 21, 2014 and became effective January 1, 2015. Further amendments were made effective January 21, 2020. The changes which are described in Standard Filing **OP-14** call for total emission limits over multi-year periods and include annual caps.

Emissions requirements for sulphur dioxide (SO₂), Nitrogen Oxide (NO_x) and Mercury (Hg) are set out below in **Figure 17** and **Figure 18**.

² NS Power, 2017-2019 Fuel Stability Plan Reply Evidence and Fuel Refresh, May 27, 2016 (M07348).

³ Air Quality Regulations made under Section 25 and 112 of the *Environment Act*, S.N.S. 1994-95 c. 1, O.I.C. 2005-87 (effective March 1, 2005), N.S. Reg 28/2005 amended to O.I.C. 2020-016 (effective January 21, 2020), NS Reg. 8/2020.

Figure 17 – Annual Emission Allowance Caps for SO₂

Year(s)	SO ₂ Tonnes		
	Unit Maximum	Annual	Cumulative
2021-2022	17,760	60,900	90,000
2023-2024	17,760	60,900	68,000
2025	13,720	45,000 ¹	141,000 ¹
2026	13,720	45,000 ¹	
2027	13,720	40,000 ¹	
2028-2029	13,720	28,000	
2030	9,000 ¹	9,000 ¹	

1. These limits are based on a Certificate of Variance for SO₂ emissions from 2025 – 2027 which supersedes the limits prescribed in the Air Quality Regulations.

SO₂ is governed by annual maximum limits as well as a multi-year cumulative emission limits. The annual SO₂ limits from 2025 to 2027 are based on a Certificate of Variance issued by the Province which allows 45 kt in both 2025 and 2026 and 40 kt in 2027. The 2026-2029 cumulative limit is 141 kt and emissions in 2030 shall not exceed 9 kt in aggregate as per the Certificate of Variance.

As set out in **Figure 18**, mercury (Hg) and Nitrous Oxide (NO_x) emissions are governed by annual limits and multi-year cumulative limits

Figure 18 – Annual Emission Allowance Caps for Hg and NOx

Year(s)	NOx Tonnes		Mercury Kg
	Annual	Cumulative	Annual
2021-2022	14,955	56,000	35
2023-2024	14,955		35 ¹
2025	11,500		35 ¹
2026-2029	11,500	44,000	35
2030	8,800		30

1. An excess of 6.7 kg of mercury emitted in 2022 was to be compensated for by reducing annual emissions by 6.7 kg in aggregate below the annual 35 kg limit between 2023 and 2025. This was achieved between 2023 and 2024.

Greenhouse gas (GHG) emissions are governed by multi-year cumulative allowances, which must be achieved for compliance, under the Greenhouse Gas Emission Regulations,⁴ as set out in **Figure 19**.

Figure 19 – GHG Emissions Limits

Year	GHG Cumulative Million tonnes
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

The forecast emissions for NOx, SO₂, Mercury and GHGs for 2026-2027 are all within the regulated annual allowances.

⁴ Greenhouse Gas Emissions Regulations made under subsection 28(6) and Section 112 of the *Environment Act*, S.N.S. 1994-95, c. 1, O.I.C. 2009-341 (August 14, 2009), N.S. Reg. 260/2009 as amended to O.I.C. 2013-332 (September 10, 2013), N.S. Reg. 305/2013.

1.2.4.1 OBPS

Greenhouse Gas (GHG) emissions are also managed in accordance with the *Output-Based Pricing System Reporting and Compliance Regulations*, effective January 1, 2023, made pursuant to the Environment Act. These regulations define Performance Standards for various fuels used in electrical generating facilities. The Performance Standards are used, along with each registered facilities total gross electrical generation, to calculate a quantity of GHG emissions that the company may emit before incurring Compliance Obligations. Facilities with GHG emissions below the allowable quantity will generate offsetting performance credits. This system does not include a facility or aggregate emission compliance limits for GHGs. Compliance Obligation costs are incurred based on actual annual emissions for each registered facility.

1.2.5 Natural Gas

NS Power forecasts the average monthly price of natural gas consumed, including transportation charges to Tufts Cove, to range from [REDACTED] to [REDACTED] with an average price over the GRA period of [REDACTED]. The price reflects no domestic gas supply. Incremental supply sourced from distant markets increases the delivered cost due to pipeline charges, but the lower cost of the commodity offsets the incremental pipeline cost.

An average price of [REDACTED] over the GRA period represents a 0.2 percent increase in the delivered unit price of natural gas relative to the 2024 GRA Refresh. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

NS Power manages financial exposure to changes in the market price of natural gas through hedging, including the use of futures.⁵ Please refer to **Section 1.4** for further detail about NS Power's hedging strategy during the 2026-2027 GRA Period.

Natural gas prices in this Application are produced using forward price curves in accordance with the POA.⁶

1.2.5.1 Natural Gas – Cost Pressures

Forecast natural gas requirements for the period 2026-2027 are lower than the 2024 GRA Refresh for all years. Natural gas consumption over the GRA period decreases as new renewable projects come online. Gas supply must be sourced from the TransCanada Pipeline Ltd. (TCPL) system and shipped across multiple pipelines, from the Repsol LNG regasification terminal (Saint John LNG) or sourced from the Algonquin system via the Atlantic Bridge expansion.

In order to secure the necessary natural gas for its operations, NS Power has executed long-term contracts with TCPL for firm pipeline transportation service starting in late 2021, and a Service Agreement with Portland Natural Gas Transmission System through a wholly owned subsidiary, NS Power Energy Marketing Inc (NSPEMI). Via NSPEMI, NS Power has a contract for 20,000 MMBtu per day for a 15-year term.⁷ This will benefit customers by providing additional fuel price and rate stability, increased fuel supply diversification, reduced emissions, and enhanced reliability and supply security.

1.2.6 Heavy Fuel Oil

Depending on the relative market prices of each fuel, Tufts Cove may generate using HFO rather than natural gas in the dual-fired steam boilers (Units 2 & 3).

⁵ Swap contracts are financial instruments used to lower volatility in pricing terms for a supply contract.

⁶ Forward price curves refer to a graph of future prices decided upon by both buyer and seller for any given commodity.

⁷ The *Approvals of Natural Gas Transportation Contracts Regulations* (N.S. Reg. 80/2019), effective June 4, 2019 and made pursuant to the *Public Utilities Act* permit the UARB to approve transportation contracts greater than two years' duration.

1 NS Power forecasts consuming [REDACTED] barrels of HFO in 2026, and [REDACTED] barrels in 2027,
2 compared to [REDACTED] barrels forecast in the 2024 GRA Refresh.

3
4 The average forecast price of HFO is [REDACTED] for the 2026-2027 GRA Period, or
5 approximately [REDACTED] delivered. This represents a 4.2 percent decrease in the
6 delivered unit price of HFO relative to the 2024 GRA Refresh.

7
8 **1.2.6.1 HFO Contracts**
9

10 There are currently no HFO contracts in place. An RFP will be issued per the process in the Fuel
11 Manual if circumstances result in an HFO vessel being required.

12
13 **1.2.7 Light Fuel Oil**
14

15 LFO accounts for a very small portion of the fuel costs: approximately 1.1 percent of total
16 consumed fuel costs in 2026 and 2027. NS Power expects to consume [REDACTED] million gallons of LFO
17 in 2026 as start-up fuel in its thermal units and for operation of the oil-fired combustion turbines,
18 and [REDACTED] million gallons in 2027. The quantity of LFO forecast is lower for both years than the 2024
19 GRA Refresh forecast consumption of [REDACTED] million gallons, reflecting projected lower peak demand
20 requirements. The average forecast price for LFO in 2026-2027 is [REDACTED]. This is a [REDACTED]
21 [REDACTED] decrease per MMBtu relative to the 2024 GRA Refresh.

22
23 **1.2.7.1 LFO Contracts**
24

25 There are currently no LFO contracts in place for the 2026-2027 period. An RFP will be issued
26 per the process in the Fuel Manual as required.

1.2.8 Renewable Energy

1.2.8.1 NS Power-Owned Renewables

The renewable energy generated by NS Power comes from hydro, wind, biomass and solar. The level of hydro generation forecast for 2026-2027 is based on a 23-year rolling average, in accordance with Section 4.10 of POA Appendix B. The use of this methodology results in a forecast of 925 GWh for 2026 and 2027.

The wind generation forecast for NS Power-owned sites is based on a three-year rolling average. NS Power forecasts annual generation of 121 GWh from Nuttby Mountain and 103 GWh from the Digby wind farm, for a total of 224 GWh from NS Power-owned sites during each year of the 2026-2027 GRA Period.

The Port Hawkesbury Biomass Plant (PHB) went into service in July 2013. PHB is a 60 MW co-generation plant operated by NS Power that produces renewable electricity. Port Hawkesbury Paper (PHP) draws steam from PHB for its paper-making process. Biomass procurement and management has evolved since July 2013, particularly with respect to winter blending, including the use of higher cost chips from round wood to help manage moisture which naturally occurs with freshly harvested biomass forest fibre. Practices have been shared with the FAM Small Working Group and have been included Fuel Manual from Revision 10 forward, in accordance with the letter from the Board dated January 26, 2016. Revision 14 of the Fuel Manual is included in **OE-01F**.

Confidential **Figure 20** below illustrates the current forecast pricing for biomass relative to the 2024 GRA Refresh and the 2025 FAM Budget.

Figure 20– CONFIDENTIAL 2024-2027 Biomass Cost Comparison

Port Hawkesbury Biomass Cost Summary				
	2024 GRA Refresh	2025 FAM	2026	2027
Fuel Costs (\$ Million)				
Energy (GWh)				
Fuel Costs (\$/MWh)				

The operation of PHB is subject to the Renewable Electricity Standards (RES) within the Renewable Electricity Regulations. Section 5(2A) of the Renewable Electricity Regulations requires NS Power to maintain PHB available as a base-loaded cogeneration facility and NS Power must operate PHB on an economic dispatch basis or as required for system reliability. Specifically, Section 5(2A) states:

(2A) NSPI must maintain the Port Hawkesbury biomass power generation plant available as a base load cogeneration facility and NSPI must operate the plant on an economic dispatch basis or as required for system reliability.

Section 6A (1) of the Renewable Electricity Regulations requires that 40 percent of NS Power’s annual energy sales be through renewable energy generation beginning in 2020:

6A (1) Each year beginning with the calendar year 2020, each load-serving entity must supply its customers with renewable electricity in an amount equal to or greater than 40% of the total amount of electricity supplied to its customers as measured at the customers’ meters for that year.

Section 6B (1) of the Renewable Electricity Regulations requires 80 percent of NS Power’s annual electricity to come from renewable sources, beginning in 2030, and Section 6B (2) stipulates that at least 1100 GWh must come from IPPs in addition to the other renewable low-impact electricity required to meet the requirements. Section 6B (3) says that NS Power may include renewable low-impact electricity acquired from sources outside Nova Scotia in order to meet its 80 percent requirement.

Section 7 (1) of the Renewable Electricity Regulations indicates that if NS Power cannot meet the renewable electricity standard for a period of 12 months or less because IPPs or other parties cannot

provide contracted supplies or because of problems arising from NS Power's renewable generation assets, NS Power must supply enough renewable electricity from other sources to make up the shortfall during the period. If NS Power is unable to meet the standard for longer than 12 months, it must apply to the Minister for permission to supply the renewable electricity from other sources to make up the shortfall.

The RES Compliance forecast for the 2026-2027 test years is set out in **Figure 21** below.

Figure 21 – RES Compliance Forecast 2026-2027

RES Compliance Forecast[1]			
		2026	2027
Energy Requirements (GWh)			
NSR including DSM effects		11,378	11,289
Losses		757	747
Sales		10,621	10,542
RES (%) Requirement		40%	40%
RES Requirement (GWh)		4,248	4,217
Renewable Energy Sources (GWh)			
NS Power Wind			
NS Power Hydro			
IPP Wind			
PH Biomass			
COMFIT Wind Energy			
COMFIT Non-Wind Energy			
IPP Other			
ML NS Block/Supplemental Block			
ML Surplus Imports*			
Forecast Renewable Energy (GWh)		4,248	5,396
Forecast Surplus or (Deficit) (GWh)		0	1,179
Forecast RES Percentage of Sales		40%	51%

1 *ML Surplus Import Renewable Energy Credits (RECs) for delivered ML Surplus Imports
2 required to achieve the 40% RES compliance target.
3
4

5 **1.2.8.2 IPP and Feed-in Tariff Contracts**
6

7 NS Power has Power Purchase Agreements (PPAs) with IPPs and COMFIT developers for
8 renewable energy from various sources. The IPP generation is grouped into two categories for
9 forecasting purposes: IPP Wind and IPP Other (which includes biomass, biogas, hydro and tidal).
10 COMFIT projects are forecast separately and include generation from wind, biomass, biogas, and
11 run-of-river hydro.
12

13 Generation forecasts for IPP and COMFIT sites are based on a three-year rolling average when the
14 data is available. If a three-year generation history is not available, the expected annual net output
15 of the facility is used.
16

17 The IPP forecast for the 2026-2027 period is set out in Confidential **Figure 22** below:

Figure 22 – CONFIDENTIAL 2026-2027 Forecast IPP Generation

	2024 GRA Refresh		2025 FAM		2026		2027	
	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)
IPP Wind								
IPP Other								
TOTAL								

Included in the IPP Wind forecast are the Point Tupper, South Canoe and Sable wind farms, all of which are partially owned by NS Power. The 2026-2027 annual generation forecast for these sites is [REDACTED] for Point Tupper, [REDACTED] for South Canoe in 2026 and 2027 respectively, and [REDACTED] for Sable Wind.

The COMFIT Program was established by the government of Nova Scotia in 2010 to support the development of local, distribution system connected, renewable energy projects by municipalities, First Nations, co-operatives, universities, combined heat & power biomass facilities, community economic development investment funds, and non-profit groups. Projects are submitted to and approved by the (former) Department of Energy and Mines. The COMFIT energy rates (\$/MWh) and standard PPA were set and approved by the NSUARB through a regulatory proceeding completed in 2011. The COMFIT forecast for the 2026-2027 GRA Period is set out in **Figure 23** below.

Figure 23 – 2026-2027 COMFIT Forecast

	2024 GRA Refresh		2025 FAM		2026		2027	
	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)
COMFIT	153	534	153	494	153	494	153	494

The decrease in COMFIT generation from the 2024 GRA Refresh is and the result of lower average generation. Forecast COMFIT site generation is based on a rolling three-year average of each project.

1.2.9 Imports

Over the 2026-2027 GRA period, there are two ways in which energy will be imported into Nova Scotia: imports through the Maritime Link and imports through the interconnection between Nova Scotia and New Brunswick. For the purpose of this Application, imports are defined as imports through the interconnection between Nova Scotia and New Brunswick and the surplus energy imported through the Maritime Link. The NS Block, including Supplemental Energy, imported through the Maritime Link is not included in the definition of imports in this Application.

As shown in Confidential **Figure 24**, the total volume of imported energy over the 2026-2027 period ranges from approximately 1,418 GWh to 1,435 GWh.

Figure 24 – 2024-2027 Forecast Import Volumes and Pricing

	2024 GRA Refresh	2025 FAM	2026	2027	
NB to NS Import Volume (GWh)					
Forecast Cost of NB to NS Imports (\$ million)					
Forecast Cost of NB to NS Imports (\$/MWh)					
Maritime Link Surplus Energy Volume (GWh)					
Maritime Link Surplus Energy Forecast Cost (\$ million)					
Maritime Link Surplus Energy Forecast Cost (\$/MWh)					
Total Import Volume (GWh)					
Total Cost of Imports (\$ million)					
Total Cost of Imports (\$/MWh)					

The methodology used to forecast the price of imports is described in Section 7.0 of the POA Appendix B.

The pricing assumption used for Muskrat Falls surplus energy is

As illustrated in **Figure 24**, the forecast volume of Muskrat Falls surplus energy in 2022, 2023 and 2024 [REDACTED] into Nova Scotia through the interconnection with New Brunswick due to transmission constraints in New Brunswick, and the favourable economics of surplus energy relative to imports through the New Brunswick interface.

1.2.10 Exports

No exports are expected across the Nova Scotia-New Brunswick tie for the 2026-2027 GRA Period due to environmental constraints.

1.2.11 US Dollar Requirements and Foreign Exchange Rates

NS Power uses forward contracts to hedge its USD requirements for fuel. A forward contract is a commitment to purchase specific securities (in this case, USD) at an agreed-upon rate at a specific date in the future. The use of forward contracts to hedge expected USD requirements results in increased fuel cost stability for NS Power's customers. NS Power's USD requirements are hedged based on known and forecast requirements, and the percentage of USD exposure hedged is aligned with the percentage of fuel hedged for that corresponding time period.

NS Power monitors and reports on its risk management strategies, including budgeted volumes of underlying positions not hedged and revisions to the budget volume.

A summary of the forecast percentage of USD requirements hedged and blended USD rate for each year in the GRA filing is shown in Confidential **Figure 25** below.

Figure 25 – 2026-2027 USD Hedge Summary (Confidential)

Hedge Summary Table				
Year	USD Volume (\$ million)	USD Hedged (\$ million)	% of USD Hedged	Average FX Rate
2026				
2027				

1.2.12 Extra-Large Industrial Active Demand Control Customer and Impact on Fuel Forecasting

NS Power performed an analysis to determine the total fuel and purchased power costs with the Extra Large Industrial Active Demand Control (ELIADC) load included and another with the ELIADC load excluded. The difference between those two scenarios resulted in an estimated fuel and purchased power cost of [REDACTED] to serve the ELIADC load in 2026 and \$65.7 million in 2027.

1.3 MARITIME LINK

1.3.1 Background

The NSUARB approved forecast Maritime Link Project costs in each year for inclusion in rates to reflect the forecast interim assessment for the Maritime Link.

The Nova Scotia Block commenced in mid-August 2021, with final commissioning of the Muskrat Falls Generating Station and the Labrador Island Link completed in April 2023. NS Power expects full delivery of the Nova Scotia Block including 894 GWh of the base (7x16) block in 2026 and 2027 and 240 GWh and 140GWh of Supplemental Energy (winter off peak) in 2026 and 2027 respectively. The Supplemental Energy Agreement is planned to be completed as of April 1, 2027, hence the reduced volume in 2027. Additionally, NS Power forecasts purchasing [REDACTED] GWh of market-priced energy from Nalcor over the Maritime Link per year in 2026 and 2027.

1.3.2 ML Assessment and Depreciation

In accordance with the requirements of the Maritime Link Cost Recovery Regulations, NSPML submits annual applications to recover forecast costs attributable to the Maritime Link from NS Power.

NSPML's forecast portion of the anticipated assessment for the Maritime Link against NS Power includes forecast Maritime Link Project costs of \$200.5 million in 2026, and \$203.9 million in 2027. Components of the anticipated assessment for 2026-2027 are set out in **Figure 26**.

1.3.2.1 Components of the Anticipated Assessment

Figure 26 – Breakdown of the Maritime Link anticipated assessment

Description	2026 (\$ Million)	2027 (\$ Million)
Depreciation	58.4	57.5
Operating & Maintenance	21.7	29.0
Debt Financing Costs ⁽¹⁾	79.8	78.0
Equity Financing Costs	40.6	39.4
Total Anticipated Assessment	200.5	203.9

(1) Includes \$41.5 million and \$40.6 million for 2026 and 2027 respectively related to interest and principal on a \$500 million Federal Loan Guarantee.

Estimates provided by NSPML are the basis for NS Power's forecast assessment.

1.4 HEDGING PLAN

Fuel costs are subject to a variety of risks including commodity market, volumetric, basis, and counterparty risk. Reducing market exposure through physical and financial hedges enables the Company to manage volatility in fuel costs.

In 2016, as a component of its Fuel Stability Plan filing and as a requirement of the *Electricity Plan Implementation (2015) Act*, the Company filed a Fuel Hedging Plan (FHP) which received approval from the Board. The FHP detailed the specific strategies, principles, and mechanisms used by NS Power in the 2017-2019 Rate Stabilization Period, but as stated in the FHP, "As the

RSP progresses, the strategies and principles in the Plan could be validly applied to 2020 and beyond assuming similar market conditions and a continued focus on rate stabilization.”

The success demonstrated by the FHP, as it largely protected customers from the significant increases in commodity prices since 2016, helps validate the approach to hedging adopted by the Company. There is no legislative requirement for the UARB to approve NS Power’s Hedging Plan for the current forecast period. However, NS Power intends to continue with the general hedging approach used over the 2017-2019 and 2020-2022 Fuel Stability Periods.

1.4.1 Hedging Plan Objectives

Fuel and purchased power (F&PP) costs represent the single largest component of NS Power’s revenue requirement. Due to the volatile nature of global commodity markets, these costs can exhibit large and unpredictable increases and decreases over time. In order to provide rate stability for customers, NS Power will use hedging to reduce market exposure when it is cost effective to do so. Recognizing that not all risks can be hedged and that the cost of hedging may in certain circumstances outweigh the benefit of hedging, the Hedging Plan is designed to achieve two primary objectives:

1. Cost-effectively reduce the expected and actual variance in F&PP costs during the current forecast period.
2. Reduce the probability of a significant increase in any fuel-related deferral resulting from under-recoveries of F&PP costs due to commodity price movements, from customers through rates during the current forecast period.

1.4.2 Hedging Principles

- Recognizing that not all risk can be removed from fuel costs, focus on reducing the overall portfolio risk when it is economic to do so.
- While hedging increases the stability and predictability of fuel costs, it does not guarantee the lowest costs are achieved.
- NS Power will target hedging 50-100 percent compared of each fuel type with periodic dynamic rebalancing of hedges and contracts to optimize the portfolio. Approximately 50 percent of NS Power's forecast FAM fuel costs for the current forecast period relate to fixed contracts for renewable energy including the forecast Maritime Link Assessment and are therefore naturally hedged. Hedging 50 to 100 percent of the remaining fuel costs, which are exposed to market forces, will result in 75 to 100 percent of forecast total Fuel and Purchased Power costs being hedged.

1.4.3 Hedging Strategies

NS Power will employ a portfolio approach to hedging by evaluating the impact of each hedge in terms of its expected reduction in overall portfolio risk using Value at Risk ("VaR") and volumetric positions as the key metrics. Where economically available, NS Power will enter into hedges for up to 100 percent of its volumetric requirements, based on the most current forecast from PLEXOS. As these forecasts are updated with new assumptions and NS Power's expected volumetric requirements for each fuel change, the portfolio of hedges will be dynamically rebalanced to align with the new forecast. From time to time, this will result in gains or losses from hedges that are unwound but will generally be offset by corresponding changes in forecast costs of the physical requirements. The purchase of fuels denominated in USD results in foreign exchange exposures which will be included in NS Power's overall portfolio risk management approach and hedged as part of the Plan in accordance with NS Power's Currency Risk Management Policy.

Due to limited liquidity in certain markets, NS Power may enter into a hedge using underlying products that are not the exact physical commodity being hedged, but are highly correlated with this commodity, and therefore provide economic protection against price movements in the underlying exposure being hedged. For example, NS Power consumes HFO for use primarily at Tufts Cove. However, the Company may not be able to hedge the exposure to HFO prices directly through the entire forecast period. In this case, other oil-based financial contracts linked, for example, to Brent Oil may be used by NS Power to provide price protection against movements in HFO prices due to the high correlation between these products. This proxy, or cross-commodity, hedging is standard practice in many markets, especially energy markets where a great diversity of physical products must be hedged with a limited number of liquid financial products.

The previous section deals primarily with managing the price risk leading up to the months in which the underlying fuels are expected to be consumed. NS Power recognizes the need to continue its risk management activities to encompass intra-month volatility and variability. Through its ability to optimize the hourly and daily dispatch of its generation fleet, NS Power will use fuel switching, physical storage capabilities, and other real optionality within its portfolio to manage intra-month fuel price variability. Where available and economic to do so, NS Power will enter into physical or financial contracts to provide additional mitigation of intra-month risk.

1.4.4 Hedging Mechanisms

This section provides a brief outline of some of the key hedging mechanisms expected to be used during the current forecast period. It is not meant to be an exhaustive list, and other products or mechanisms may be used by NS Power. NS Power will use a combination of physical and financial contracts. A more detailed description of the products and trade types can be found in the FHP which is included in **OE-01J**. The Company notes that many of these mechanisms are currently used are consistent with the mechanisms in the approved FHP.

1.4.4.1 Physical Contracts

By entering into fixed price contracts, NS Power agrees to pay a known price for a physical fuel or purchased power, thereby eliminating exposure to underlying commodity market prices. These contracts may be for fixed volumes or may include volumetric optionality for NS Power. Generally, NS Power enters into these contracts when it has a high degree of confidence that it will require the physical fuel at the time it will be delivered or that there is sufficient storage capacity to allow for deferral of consumption to another time period where its consumption is economic.

1.4.4.2 Financial Contracts

Financial contracts primarily take the form of futures, forwards, and swaps. Generally, NS Power is the buyer of these contracts which means it will be obligated to pay a fixed price known at the outset of the contract, and in return will receive a floating payment (or stream of payments) linked to an underlying market price. If market prices increase, these financial contracts will result in a net payment to NS Power which will help offset the higher price NS Power will be required to pay in the market for the underlying physical fuel or purchased power. If the underlying market prices decrease, NS Power will make a net payment to its financial counterparty; however, it is likely that the cost to NS Power of the physical commodity will have decreased as well. In either case, the impact of financial hedging is to offset the higher or lower prices that must be paid for the physical fuel or purchased power, thereby reducing the variability in these costs and providing for greater fuel cost stability and predictability. NS Power may use a combination of centrally cleared exchange-traded and bilateral over-the-counter financial contracts. NS Power may also use options or structured physical and financial products if there is sufficient market liquidity, and these products are determined to hedge underlying market exposures economically.

2026-2027 GRA Appendix 5B has been removed due to confidentiality.



**Environment and Climate Change
Office of the Minister**

PO Box 442, Halifax, Nova Scotia, Canada B3J 2P8 • Telephone 902-424-3736 • novascotia.ca

PNS-53466-P1K7V0

March 25, 2025

David Pickles
COO, Nova Scotia Power Incorporated
PO Box 910
Halifax, NS B3J 2W5

Dear Dave Pickles:

Thank you for your letter dated March 24, 2025, where you requested flexibility in the sulphur dioxide emission caps as written in the Air Quality Regulations. This correspondence is in response to the request for flexibility and your proposed recovery plan.

After careful consideration, I have decided to approve your request for flexibility as detailed in your letter. As you are aware, diversion from Schedule C of the Air Quality Regulations, NS Reg. 8/2020, requires a certificate of variance. I have decided to approve your request and provide the certificate of variance based on four key elements:

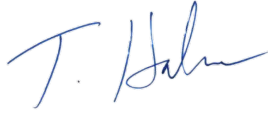
- 1) The emission and recovery schedule proposed will result in a net-neutral impact to the environment since NSPI will emit below the 2030 to 2034 emission limits to recover an equal or greater amount of SO₂ than will be over-emitted between 2025 to 2029.
- 2) The over-emission from the 2021-2022 compliance period will also be recovered by 2034.
- 3) The longer timeframe will allow NSPI to recover the excess SO₂ emissions without increasing electrical costs for Nova Scotian rate payers.
- 4) The recovery plan is a viable approach that does not impact grid reliability.

Under Section 61 of the *Environment Act*, the Minister can issue a certificate of variance if the Minister considers the variance is not likely to cause an adverse effect. In this instance, I consider a certificate of variance to be appropriate since the excess SO₂ emitted will eventually be recovered, resulting in a net neutral impact to the environment, and this section of the Regulations is only applicable to NSPI. Additionally, NSPI is expected to adhere to all other requirements of the Regulations, including meeting all applicable ambient air quality standards at each of their fossil fuel-fired thermal power generating facilities.

The certificate of variance, which accompanies this letter, includes terms and conditions you are required to follow as you carry out your activities. Matt Seaboyer, Director of Air Quality and Resource Management, is available for any questions you may have.

I look forward to seeing NSPI's progress towards minimizing SO₂ emissions and working together on our shared goal of continuing to improve air quality for all Nova Scotians.

Sincerely,

A handwritten signature in blue ink, appearing to read "T. Halman".

Honourable Timothy Halman, MLA
Minister of Environment and Climate Change

c: Peter Greg, CEO, Nova Scotia Power Incorporated
Lora MacEachern, K.C., Deputy Minister, Environment and Climate Change
Karen Gatien, Deputy Minister, Energy
Janet MacKinnon, Executive Director, Environment and Climate Change
Matt Seaboyer, Director, Air Quality and Resource Management, Environment and Climate Change

Appendix 6A

FAM Framework

APPENDIX 6A FAM FRAMEWORK

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1 FAM FRAMEWORK

The Fuel Adjustment Mechanism (FAM) is governed by the Plan of Administration (POA) which was introduced for the 2009 calendar year and which is periodically updated and approved by the NSEB. The FAM also uses the Cost of Service (COS) information for each of the rate classes to apportion the fuel costs appropriately among the customers.

1.1 FAM Plan of Administration

The POA outlines the application and administration of the FAM. It includes descriptions of the base cost of fuel, adjustment components, calculation methodologies, audit provisions, and stakeholder review and discovery, all of which have been developed in conjunction with stakeholders and approved by the NSEB.

NS Power files revisions to the POA and appendices either on its own or in response to NSEB directives or legislation.

The current POA was approved by the NSEB¹ in January 2024 and is included as **OE-01R**. The POA states that the BCF can be reset in a General Rate Application, every second year as part of the FAM adjustment process, or as directed by legislation or an order of the NSEB.

As part of the 2026-2027 GRA, NS Power is proposing a new amended POA which includes a new BCF for the test period. The POA and the appendices were designed for implementation on an annual or biennial basis. The current POA accommodates a two-year forecast period with adjustment to some of the components of the POA.

As part of the current GRA filing, NS Power will be seeking approval of an updated POA which reflects the proposed test period.

¹ M11127, NS Power Application for Amendment to the FAM Plan of Administration, Revision 12 approved by the NSUARB on January 22, 2024.

NS Power is also seeking changes to the POA. Details of the POA changes are outlined below and the proposed POA (redline and clean versions) are included as **Appendix 6B**.

1.2 FAM Components

The UARB approved the implementation of the FAM in the 2009 General Rate Application (GRA) effective January 1, 2009. The FAM was originally structured to have three rate components: the BCF, the AA and the BA, and an incentive component. The incentive component was removed from the 2017-2019 POA and NS Power is not seeking to have it reinstated for the 2026-2027 GRA.

The rate components of the FAM are described below.

1.2.1 Base Cost of Fuel

NS Power resets its BCF in accordance with the POA. The BCF is the test year forecast of fuel, energy and purchased power costs which are incorporated into customer rates.

The forecast methodology is found in Appendix B of the FAM POA. The BCF amount is used to calculate the fuel and purchased power cost component of customer electricity rates beginning on January 1 in each of 2026 and 2027.

The difference between NS Power's actual fuel costs and fuel costs established to be recovered through the BCF component of rates accumulates each month in the FAM as a regulatory asset (if NS Power under-recovers its actual fuel costs) or as a regulatory liability (if NS Power over-recovers its actual fuel costs).

1.2.2 Actual Adjustment (AA)

The AA represents the difference in the current year between the amount spent on fuel and the fuel-related revenue recovered from customers. At year end, the under- or over-recovered amount (plus the applicable interest) will be the total FAM deferral amount for that year. For purposes of

establishing customer fuel rates to recover or return the FAM deferral amount, and as noted in Section 1.3 below, NS Power files an application which includes 12 months of actual fuel data (October to September).

The total deferral amount is divided by the upcoming year's sales forecast in order to determine the AA rate.

1.2.3 Balance Adjustment (BA)

The BA represents the difference in the prior year between the actual fuel costs and the fuel-related revenue recovered from customers. As noted above, although the FAM AA calculation uses 12 months of actual data so a balancing adjustment is no longer required to true up the actual fuel costs during the year,² there are additional amounts carried over from previous years which form part of the BA.

The BA comprises previously deferred FAM amounts and any residual amount of the AA related to previous years not fully refunded or recovered by the AA. The BA has also been used for returning any non-fuel revenues exceeding the approved rate of return to customers (by settlement agreement, legislation or NSUARB order). The BA rate is established using the cumulative under- or over-recovery divided by forecast sales for the period. Residual BA at the end of a year is applied to the following year and is used in the determination of future BA rates. In this way, only actual costs are recovered from customers.

² Although the actual AA figures will be based on 12 months of actuals, there will be a BA based on the difference between the forecast sales and the actual sales and as a result of financing costs on the AA balance while it is being collected or refunded. The AA is set based on forecast sales for the year, but actual AA recovery will differ from forecast.

1.3 AA/BA Reporting and Rider Application Process

In 2018 the NSUARB changed the requirement for the AA/BA reporting process from the use of 10 months of actual values (January-October) and two months of forecast values (November-December) to the use of actual fuel data from October 1 to September 30 each year to allow for a filing in October.¹

NS Power files its 12-month AA/BA Rider Application (Q4 and the next Q1-Q3) in Q4 of the following year. Information on the fluctuations between actual and FAM Budget by fuel type is set out in the FAM Monthly Reports on page M-1 and variances by price and volume by fuel type are set out on page M-6 (Confidential).

1.4 Plan of Administration Documentation

The POA documentation needs to be modified to reflect NS Power's current practices and the proposed 2026-2027 GRA Period. A redline and clean version are attached as **Appendix 6B** to the GRA Direct Evidence.

The proposed revisions to the POA main document are set out below.

1.4.1 GRA Period

References to the proposed 2026-2027 GRA Period are updated throughout the redline POA main document.

1.4.2 Addition of Community Solar Energy Credit Rider

Changes are located in section 3.2.8 Purchased Power.

On October 1, 2024, NS Power submitted an application for approval of the Community Solar Energy Credit Rider. In that application the company noted its intent to file revisions to the Plan of Administration upon approval of the Application:

¹ M08656, NSPI AA/BA Process including 2016/2017 FAM Audit Timeline, UARB Letter, NSUARB-NSPI-P-887, July 4, 2018.

The last paragraph of the application stated:

The on-bill credit related to the Community Solar Program, and other emerging customer renewable energy programs (e.g. Green Choice Program), is a new concept that, at present, is not explicitly identified as an allowable fuel cost eligible for recovery through the Fuel Adjustment Mechanism (FAM). On-bill credits for customer renewable energy programs, like the costs related to PPAs under these programs, are costs appropriately included as fuel and purchased power costs and are eligible for recovery through the FAM. **Subject to the Board's approval of the Community Solar Energy Credit Rider, the Company intends to separately file an application to propose revisions to the FAM Plan of Administration (POA) to explicitly recognize this Program, and other emerging customer renewable energy programs, as FAM costs.**

NS Power provided further comments on the POA revision process in response to CA IR-4:

Should the NSUARB approve the proposed Community Solar Energy Credit Rider, NS Power will review the proposed revisions with the Fuel Adjustment Mechanism (FAM) Small Working Group (SWG) at the first opportunity after receiving approval. Once feedback has been received from the FAM SWG, NS Power will seek NSUARB approval of the revisions to the Plan of Administration.

On February 12, 2025 the NSUARB issued the Decision on the NS Power application for approval of its Community Solar Energy Credit Rider.² The Decision stated the following about the POA at para. 17:

In its application, NS Power noted that it intends to file an application to propose revisions to the FAM Plan of Administration to explicitly recognize the community solar program, and other emerging customer renewable energy programs, as FAM costs. While there were information requests and comments about this in this matter, it is not presently before the Board for disposition.

NS Power distributed the POA to the SWG on March 21, 2025. During the SWG meeting on April 4, 2025 the changes were presented, and there were no comments.

1.4.3 Addition of three categories of allowable fuel costs

On May 8, 2023, NS Power submitted an application to the NSEB for approval of four additional

² M11911, NS Power Community Solar Energy Credit Rider, NSEB Decision, February 12, 2025.

fuel costs to the POA. One was accepted, three were not. The Board stated in its decision - “Given the nature of the first three costs, the Board is willing to consider inclusion at a future date, in conjunction with a GRA.” The three additional costs added are outlined below including forecast cost for the test period:

Nuttby Wind Farm - Premium/discount component of the maintenance contract – new section 3.2.18

The premiums and discounts related to the maintenance component of wind farm contracts of partially owned wind generators have been captured in the FAM, as specified in section 3.2.8, but NS Power has not included any premiums and discounts for maintenance contracts for wind farms that are wholly owned by NS Power. These costs are not included elsewhere in the FAM, and the exclusion was likely an oversight. The premiums and discounts relate to the Nuttby Wind Farm and the cost is driven by any generation above or below the expected generation that the maintenance contract is based upon. NS Power proposes to start including these costs in the FAM, since these costs are allowable costs for partially owned facilities and the cost fits the description of allowable fuel costs specified in section 3.2, Allowable Fuel and Purchased-Power Costs: “Allowable fuel expenses will include normal, recurring, non-capital expenses that have been prudently incurred.” To accommodate the inclusion of costs related to the premiums and discounts related to the maintenance component of wind farm contracts for wholly owned facilities, NS Power proposes the addition of section 3.2.18. NS Power forecasts the annual cost to be \$800K in 2026 and \$900K in 2027.

Inclusion of ash haulage costs for solid fuel (section 3.2.2) and heavy fuel oil (section 3.2.3)

Ash haulage costs, under the current POA, are only associated with limestone (section 3.2.7) but other plants that consume solid fuel and heavy fuel oil also produce ash that needs to be removed, with cost varying by consumption. NS Power is seeking approval to start including these costs in the FAM since these costs are allowable costs in section 3.2.7 and the cost fits the description of allowable fuel costs specified in section 3.2, Allowable Fuel and Purchased-Power Costs as quoted above. To accommodate the inclusion of ash haulage costs, NS Power proposes the addition of specific language to sections 3.2.2 and 3.2.3. NS Power forecasts the annual cost to be \$1.7M in 2026 and 2027.

Inclusion of Tufts Cove wharf / buoy chain inspection and maintenance costs (section 3.2.3)

Operating and maintenance costs related to the Point Tupper Marine Terminal (PTMT) are specified for inclusion in the FAM (section 3.2.2), however, costs related to operating and maintenance of the Tufts Cove pier are not specified. While the Tufts Cove pier, used for unloading heavy fuel oil, is smaller than the PTMT, the category of costs related to each pier is the same in that it is necessary for the continued and safe unloading and handling of fuel required for generation facilities. NS Power is seeking approval to start including these costs in the FAM

since these costs are allowable costs in section 3.2.2 and the cost fits the description of allowable fuel costs specified in section 3.2, Allowable Fuel and Purchased-Power Costs as quoted above. NS Power forecasts the annual cost to be \$56K in 2026 and \$57K in 2027. To accommodate the inclusion of Tufts Cove wharf / buoy chain inspection and maintenance costs, NS Power proposes the addition of specific language to section 3.2.3.

1.4.4 Removal of Appendix D “FAM Regulatory Calendar”

NS Power is requesting that the NSEB agree to remove the requirement to include a calendar in the POA. Appendix D, when drafted, includes dates and processes that are unknown at the time of approval of the POA. As a result, Appendix D is not a reliable source for important and relevant FAM dates. While the dates for monthly, quarterly and annual reports is known, other dates and complete processes, like the FAM Audit, AA/BA proceeding and BCF process are unknown. In terms of the monthly, quarterly and annual reporting obligations, the timelines are already specified in section 4.0 of the POA. For all FAM proceedings, including the FAM Audit, AA/BA proceeding and BCF processes, the Board issues a Hearing Order that specifies the process and dates to be followed. These Hearing Orders are the accurate resource for NS Power and stakeholders to understand processes and timelines.

1.4.5 Cost of Service Updates

NS Power undertook stakeholder engagement throughout 2024 around its Cost of Service. In Appendix 13A NS Power has proposed changes to its COS, including changes to the COS for FAM. NS Power has updated the FAM POA within section 3 to reflect the proposed changes to the FAM COS.

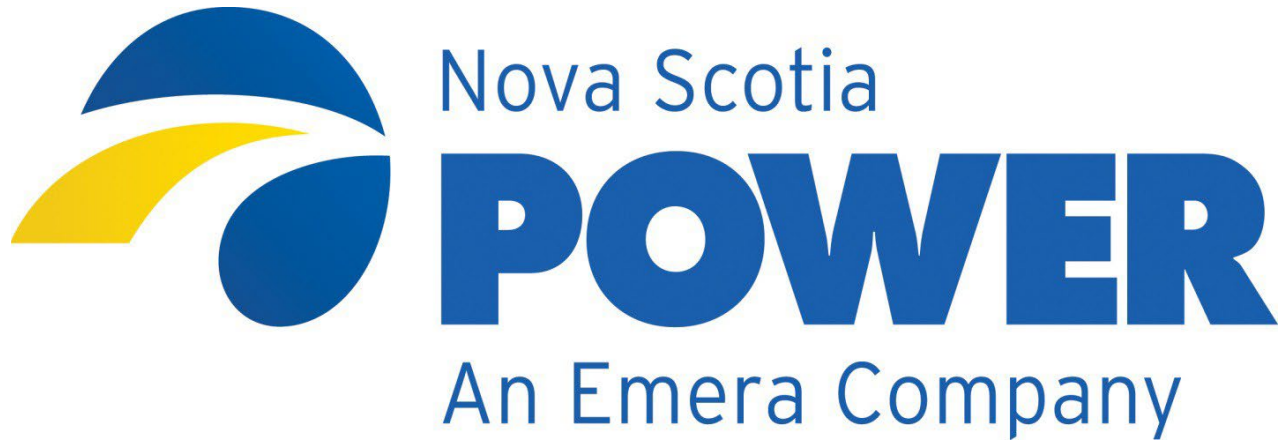
1.4.6 Housekeeping Updates

The revised POA submitted includes a number of changes related to housekeeping items, including:

- References to Nova Scotia Utility and Review Board (NSUARB) are changed to Nova Scotia Energy Board (NSEB);
- Updated dates to reference the 2026/2027 GRA process;
- Updates to section 3.1 to accommodate moving to a FAM class and the

- recognition of retail suppliers;
- Updates to section 3.2.17 to recognize the current emissions reduction program in NS (deleted references to Cap-and-Trade) and deleted section 3.2.18 as there is no revenue associated with the current emission reduction program; and
 - Addition of template A15 to Appendix C to allow for the reporting in the annual report of wind curtailment data in response to 2022-2023 FAM Audit Recommendation X-6.

NS Power requests approval of the proposed POA changes as part of this Application.



**Fuel Adjustment Mechanism
Plan of Administration
in Effect for 2026-2027**

May 28, 2025

NS Power
FUEL ADJUSTMENT MECHANISM
PLAN OF ADMINISTRATION IN EFFECT FOR 2026-2027

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Appendix A – Sample FAM Calculations

Appendix B – Forecasting Methodology

Appendix C – FAM Reporting Requirements and Templates

Appendix D – FAM Tariff

1.0 GENERAL DESCRIPTION

This document describes the plan for administering Nova Scotia Power Inc.'s (NS Power) Fuel Adjustment Mechanism (FAM), which was approved by the Nova Scotia Utility and Review Board (as of April 1, 2025 referred to as the Nova Scotia Energy Board (NSEB or Board)) in its decision letter issued on December 11, 2008. The FAM provides for the recovery of fuel and purchased power costs beginning January 1, 2009.

The Plan of Administration (POA) outlines the application and operation of the FAM. The Base Cost of Fuel will be calculated as set out in Section 2 "FAM COMPONENTS".

The Base Cost of Fuel can be reset in a General Rate Application (GRA), every second year as part of the FAM adjustment process, or as directed by legislation or an order of the Board. A forecast of costs and load for each test year will be used to set the Base Cost of Fuel. The change in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the Cost of Service Study (COSS).

Stakeholders shall have the opportunity (and access to information) to challenge the implementation of the methodology and the contents of any forecast prior to its use in resetting the Base Cost of Fuel. Both the implementation of the methodology and the forecasts will be the subject of a formal Board proceeding in which stakeholders will have their current rights as in general rate cases.

Stakeholders shall have the opportunity to challenge NS Power's fuel costs (and to secure access to information) at each annual or applicable hearing before the Board consistent with their current rights in general rate cases. The Board will also subject NS Power's FAM accounts to audits as per section 5.0 "Audit and Oversight" and as it deems appropriate.

The FAM will pass through the difference between actual costs and the Base Cost of Fuel to customers calculated on a ¢/kWh basis.

Interest will be added to all over/under-balance amounts and calculated at NS Power's Annual Weighted Average Cost of Capital (WACC).

The FAM will recover fuel cost changes resulting from over/under-recovery amounts, including an Actual Adjustment (AA) and a Balancing Adjustment (BA) for each rate class. The FAM adjustment is the difference between actual fuel cost and the Base Cost of Fuel) and will be calculated on a ¢/kWh basis.

2.0 FAM COMPONENTS

Each January 1 through December 31 period shall constitute a distinct FAM year. Under the FAM, an adjustment will normally be calculated once per year to reflect the over/-under recovery.

The FAM adjustment will consist of two components designed to provide for the recovery of fuel and purchased power costs. Those components are:

1. The Actual Adjustment Component (AA)
 - a. Established at a rate expected to recover the amount of the difference between the prior FAM year's actual fuel and purchased power costs and those recovered through the Base Cost of Fuel Component to the end of September of the prior year and October to December of the year before that, making 12 months of actuals.
2. The Balancing Adjustment Component (BA)
 - a. The Balancing Adjustment Component will provide for a correction to ensure that over/under-recovery produced by the Actual Adjustment Component is tracked and refunded to or recovered from customers.
 - b. The Balancing Adjustment Component may also include, subject to specific Board approval, deferrals of fuel and purchased power costs existing at the time of FAM adoption or that result from any future Board decision.

3.0 CALCULATION OF THE FAM RATE

NS Power's FAM is a forecasted base fuel rate operating on an annual cycle that includes an over/under recovery mechanism consisting of an Actual Adjustment (AA) and Balance Adjustment (BA).

The following formula will be used to determine the fuel adjustment factor (Fuel Adjustment Factor) for each upcoming FAM period:

Fuel Adjustment Mechanism Formula = AA + BA

Where:

1. AA is the Actual Adjustment that accounts for any differences between revenues collected through the application of the FAM during the previous one year period and actual Fuel Costs for each rate class (adjusted for the FAM incentive on an overall fuel cost basis) for the same one year period.

The AA rate is calculated for the following year on the basis of the over- or under-recovery of the Base Cost of Fuel at the end of September (year 1). Any over- or under-recovery from October to December will not be included in the rate calculation and will be deferred for recovery until the year subsequent to the following year (year 3). The actual AA starting balance for the following year (year 2) is the over- or under-recovery of the Base Cost of Fuel at the end of December (year 1).

2. BA is the Balance Adjustment that accounts for any over- or under-recovery amounts resulting from prior adjustments. The BA will also be the mechanism used to manage any deferred fuel and purchased power costs approved by the Board for inclusion in the BA.

The BA rate is calculated for the following year (year 2) on the basis of the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of September (year 1). The actual BA starting balance for the following year (year 2) is the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of December (year 1).

Appendix “A” to this Plan of Administration titled “Sample FAM Calculations”, provides a step by step detailed calculation of the overall Base Cost of Fuel, Actual Adjustment (AA), and Balancing Adjustment (BA) for a sequence of years starting in 2009. The applicable calculations illustrated in Appendix “A” will be used as outlined in the FAM Tariff in Appendix D.

Calculation of the Actual Adjustment Factor (AA) and Balancing Adjustment Factor (BA) FAM components will follow the fuel-related cost allocation methodology.

Actual (i.e. after the fact) fuel-related costs will be allocated in the same manner as the test year fuel-related costs used in setting base rates. In summary, this procedure will operate as follows:

1. A portion of the total fuel-related costs will be assigned to the following categories of non-FAM classes based on their fuel costing principles:
 - a. The below-the-line bundled service rates for Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power classes.
 - b. The Extra-Large Industrial Active Demand Control (ELIADC) class.
 - c. The unbundled tariffs: Open Access Transmission Tariff (OATT), , Energy Balancing Service Tariff (EBS), Renewable to Retail Market Transition Tariff (RTT).
 - d. All remaining fuel-related costs will be allocated to ATL classes and the

Wholesale Market Backup/Top-up Service Tariff (BUTU).

2. For ATL and BUTU classes the following costs and credits

- a. NS Power's plant fuel costs
- b. costs of biofuels of purchased biomass generation
- c. non-firm imports costs
- d. export revenue credits

will be classified 100 percent to energy and allocated to each class based on its relative contribution to monthly energy requirement.

3. Fuel costs assigned to the Wholesale Market Non-Dispatchable Supplier Spill Tariff will be based on avoidable fuel costs.

4. Costs of Firm Imports and non-fuel portion of in-province Purchased Power will be classified to demand and energy based on the load factor of the above-the-line classes.

- a. The demand-related portion of the above costs will be allocated to each class based upon its relative coincident contribution to the three monthly system peaks (3CP) occurring in December, January and February. The energy portion of the above costs will be allocated to each class based on its relative contribution to monthly energy requirement.
- b. In-province purchased power from biomass generation will be broken out between fuel and non-fuel components in the same proportion as that of the Port Hawkesbury biomass plant.

5. In order to ensure that allocated fuel-related costs are aligned with the revenue expected from approved rates for each class, the costs will be scaled up or down using the revenue-to-cost ratio (R/C ratio) for each class. The resultant costs by class will then be reconciled to the total ATL fuel-related costs based on their

relative share of the total fuel costs.

6. The interest amount on the over- or under-recovery of fuel costs is apportioned to the individual rate classes at the end of the year on an annual basis using the following approach:
 - a. In a year where the interest amount owed to customers by NS Power at the end of September coincides with an over-recovery of fuel costs to the end of September in that year, or where the interest amount owed by customers to NS Power at the end of September coincides with an under-recovery of fuel costs to the end of September in the year, the interest amount will be apportioned to each class based on its relative share of the year-end fuel cost variance during that year.
 - b. In a year where there is an interest balance owed to customers even though there has been an under-recovery of fuel costs to the end of September, or there is an interest balance owed to NS Power even though there was an over-recovery of fuel costs, NS Power will apportion the outstanding interest balance to each rate class on the basis of the relative class shares in the actual annual fuel cost incurred by NS Power.

The apportioned interest expense or credit is added to the fuel cost variance by class to provide the total fuel and interest (over)/under-recovery amount by class.

In order to determine the factor to be used as the Actual Adjustment (AA) component of the FAM, fuel-related costs allocated to each class in base rates will be subtracted from actual fuel-related costs allocated to each rate class. The difference in costs will be divided by the forecast energy sales (i.e. excluding line losses) to yield a credit or additional charge (in cents/kWh) that would normally be applied to customers' bills for the subsequent year. For the 2026-2027 GRA Period, the AA/BA credit or charge (in cents/kWh) will be determined in 2026 for 2027 AA/BA riders. Any under/over recovered BCF amounts at the end of September

2026 will be used to determine the AA charge or credit for 2027.

The Balance Adjustment (BA) component of the FAM will be set to recover or refund any under or over-recovery due to prior adjustments. These adjustments may include variances in actual and forecasted sales volumes that were applied to the prior year AA that result in an under or over-recovery, any over- or under-recovered BCF amounts from October to December of the prior year, along with the associated interest component. The BA component may also capture other fuel-related factors subject to Board approval.

3.1 Treatment of load migrating between FAM/non-FAM classes

When a customer transitions some or all of its load between FAM- and non-FAM classes, NS Power shall treat the customer's migrating load in accordance with Special Condition 3 of the FAM Tariff.

3.2 Allowable Fuel and Purchased-Power Costs

This section of the POA provides a framework for the fuel and purchased-power costs eligible for recovery through the FAM. Those costs will include allowable fuel expenses plus purchased-power expenses, less revenues from exported power and other fuel- and power-sale revenues.

Allowable fuel expenses will include normal, recurring, non-capital expenses that have been prudently incurred. Discrepancies between the value of measured fuel quantities and the book value of each fuel may also be included if those discrepancies are reasonably supported through surveys, tank level readings and pipeline reports. Exceptional or non-recurring costs appropriately classified as a fuel and purchased power cost will be brought to the attention of the Small Working Group for review for inclusion in the FAM.

NS Power understands that these costs are subject to audit, both internal and external, and to approval by the NSEB. Allowable Fuel and Purchased Power Costs will include the

following items:

3.2.1 Natural Gas

- Natural Gas Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Pipeline Reservation Fees, Tolls, Penalties (such as imbalance charges)
- Pipeline Losses
- Natural Gas Storage Fees
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502050	REG FUEL GAS CONSUMED
502160	REG FUEL GAS SOLD
502100	REG FUEL GAS CONSUMED FX
502200	REG NATURAL GAS PIPELINE TOLL
502150	REG FUEL GAS CONSUMED COMMODITY DERIVATIVES
502170	REG FUEL GAS PIPELINE LOSSES
504410	REG GRID SALES FUEL NATURAL GAS CLEARING
504400	REG GRID SALES FUEL NATURAL GAS

3.2.2 Solid Fuel

Solid fuel costs are collected into three categories: Inventoried Costs, Costs Directly Applied, and Costs Expensed Through Plant Fuel Handling Adjustments. Those categories include the following costs:

- Inventoried costs
 - Commodity Costs - Coal, Petroleum Coke
 - Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
 - Third-party Quality Testing and Sampling
 - Transportation Costs (e.g. by rail, barge, vessel, truck etc.)
 - Includes loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
- Costs directly applied:
 - Third Party Fuel Handling, Transportation (e.g. movement between Long Term Dead Storage/Bear head and plants) and Maintenance related to Coal Piles
 - Storage fees (e.g. lease, handling fees, facility fees)
 - Environmental Compliance Fees (e.g. Provincial Air Emissions Fees)
 - Rail Car Costs (e.g. lease, repair, maintenance)
 - International Pier Operating & Maintenance Costs
 - Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)
- Costs expensed through the Plant Fuel Handling Adjustment:
 - At each thermal coal unit a demarcation point has been defined as the reclaim hoppers. Any solid fuel handling and transportation expenses up until the point of the reclaim hopper are considered a FAM expense. Costs will include the following items:

- NS Power labour and associated costs for Equipment Operators, Mechanics, Supervisors related to fuel handling and Lab Techs related to testing
- Costs associated with measurement of inventory (e.g. surveys, density testing)
- Non-capital materials for fuel handling (e.g. tools, replacement parts for machines)
- Repair costs for fuel handling equipment and infrastructure
- Heavy Equipment operating costs for fuel handling (e.g. rental and fuel)
- PTMT Pier Operating & Maintenance costs

Costs in all three Solid Fuel categories – inventoried, directly applied and expensed through plant fuel handling adjustments – are normally recorded in the following accounts in NS Power’s Chart of Accounts:

502250	REG FUEL COAL CONSUMED
502260	REG FUEL COAL CONSUMED IMPORT
502270	REG FUEL COAL CONSUMED DOMESTIC
502290	REG FUEL COAL CONSUMED OTHER
502280	REG FUEL COAL CONSUMED PETCOKE
502350	REG FUEL COAL CONSUMED FUEL TESTING
502300	REG FUEL COAL CONSUMED FX
504050	REG GRID SALES FUEL COAL CONSUMED

3.2.3 Heavy Fuel Oil

- HFO/Bunker Fuel Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Quality Testing and Inventory Measurement Costs

- Standby Emergency Response Services and third party compliance program
- Third Party Supervision of Unloading
- Transportation Costs (e.g. rail, barge, vessel, truck etc.)
 - This would include loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
- GHG Emission Compliance Program costs
- Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)
- Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502400	REG FUEL BUNKER C CONSUMED
502460	REG FUEL BUNKER C CONSUMED COMMODITY DERIVATIVES
502450	REG FUEL BUNKER C CONSUMED FX
504100	REG GRID SALES FUEL BUNKER C CONSUMED

3.2.4 Diesel Oil

- Diesel Commodity Consumed
- Transportation Costs
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502500	REG FUEL DIESEL OIL CONSUMED
--------	------------------------------

504450 REG GRID SALES FUEL DIESEL

3.2.5 Light Starter Oil

- LFO (Light Fuel Oil) Commodity Consumed
- Transportation Cost
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502550 REG FUEL LIGHT OIL CONSUMED

3.2.6 Fuel – Additives

- Additives - Ultramag, FireShield, etc.
- Transportation Costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502600 REG FUEL ADDITIVES CONSUMED

502650 REG FUEL LIMESTONE CONSUMED

504200 REG GRID SALES MERCURY SORBENT

504250 REG GRID SALES MERCURY SORBENT FX

3.2.7 Fuel – Limestone

- Limestone and related transportation
- Limestone Ash Hauling and Equipment Rentals
- Limestone Royalties
- Water Royalties

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

502650 REG FUEL LIMESTONE CONSUMED

3.2.8 Purchased Power

- Independent Power Producer (IPP) Purchases (e.g. Wholesale Market Non-Dispatchable Spill Tariff) IPP, COMFIT production bonuses and penalties and costs associated with renewable energy programs (e.g. on bill credits for community solar programs)
- Community Feed in Tariff (COMFIT) Purchases
- Developmental Tidal Feed in Tariff (Tidal FIT) Purchases
- Import Power Purchases and associated fees (e.g. transmission tariffs and losses)
- Renewable Energy credits
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502700 REG PURCHASED POWER

502750 REG PURCHASED POWER FX

502800	REG PURCHASED POWER COMMODITY DERIVATIVES
502850	REG PURCHASED POWER IPP PRE 2001
502950	REG PURCHASED POWER COMFIT SMALL
502900	REG PURCHASED POWER IPP POST 2001
502710	REG PURCHASED POWER INADVERTENT
503050	REG PURCHASED POWER COMFIT LARGE
504300	REG GRID SALES PURCHASED POWER
502720	REG PURCHASED POWER NET METERING

3.2.9 Fuel Biomass

- Biomass Commodity Consumed
- Maintenance and Operating expenses for Fuel Handling (allocation between OM&G and FAM)
- Third Party Quality Testing and Inventory Measurement Costs (e.g. surveys, density testing, sampling)
- Storage fees (e.g. lease, handling fees, facility fees)
- Environmental Compliance including Silviculture Fees and harvest audits
- Transportation Costs (e.g. by barge, truck etc.)
- GHG Emission Compliance Program costs
- Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)

At the biomass plant a demarcation point has been defined as the bin collecting conveyor. Any fuel handling and transportation expenses related to steam for generation up until the point of the bin collecting conveyor are considered a FAM expense.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502380 REG FUEL BIOMASS CONSUMED

3.2.10 Fuel – Mercury Sorbent

- Additives – Powder Activated Carbon (PAC) and Calcium Chloride
- Transportation Costs
- Costs relating to a Hg (mercury) Diversion Program that has been approved by the Minister of Environment under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

504200 REG GRID SALES MERCURY SORBENT

504250 REG GRID SALES MERCURY SORBENT FX

3.2.11 Grid Sales Revenue

Revenue from power exports net of any transmission tariffs and losses. This includes Renewable Energy Credits arising out of the sale of renewable energy in the New England market.

3.2.12 Natural Gas Revenue

Revenue from the resale of natural gas.

3.2.13 Miscellaneous Revenue and Recoveries

Revenues from joint partnerships in wind farms (including the cost of NS Power's ownership which is applied to purchased power) and any other fuel-related miscellaneous revenues. These revenues include steam sales to Port Hawkesbury Paper and steam sales at the Trenton Generating station.

The following accounts are normally used to record revenues from power exports and natural gas resales, revenues from joint partnerships in wind farms, and other miscellaneous revenues related to fuel.

417300	REG GRID SALES REVENUE
503200	REG NATURAL GAS REVENUE
503250	REG NATURAL GAS REVENUE FX
503300	REG WIND RECEIVABLES PURCHASED POWER
503350	REG WIND RECEIVABLES FUEL FOR GENERATION
535850	MISC REVENUE

These revenues will offset FAM-eligible fuel and purchased-power costs.

At times, revenues may be recorded as credits to related expense accounts, depending on their nature and applicable accounting guidelines. In these events, full explanations will be provided regarding why they were not offset against FAM-eligible fuel costs.

3.2.14 Foreign Exchange

All NS Power Fuel Accounts are subject to adjustments to record expenses or revenues denominated in foreign currencies and include the gain or loss on currency hedges entered into for the purpose of fuel procurement.

3.2.15 Limited-Duration Fuel Testing

These fuel testing costs (including solid fuel, liquid fuel and additives such as PAC) consist of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third party testing and analysis), and only to the extent incurred as part of limited duration test burns occasionally made by the Company. They shall be limited to non-capital costs and they shall be separately identified in the Company's accounting records.

3.2.16 BTL Costs

- Spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff
- Fuel cost incurred in providing service under the Wholesale Market Backup/Top-up Service tariff, less revenue received under the Wholesale Market Backup/Top-Up Service tariff net of non-fuel items

3.2.17 GHG Emission Compliance Program Costs

- The cost of Fund Credits under the Nova Scotia GHG Output Based Pricing System (OBPS) emissions compliance programs.
- Transaction fees for purposes of purchasing GHG OBPS Fund Credits).

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

503400 REG EMISSION ALLOWANCE EXPENSE

3.2.18 NSP Owned Variable Production Costs

- Third party production bonuses and penalties for NSP owned power production.

3.3 Calculation of Fuel Costs

The fuel costs in the Base Cost of Fuel recovered through the FAM include allowable fuel and purchased power expenses (as noted in section 3.1 above) less revenues from exported power.

3.4 Deferrals

During the 2026-2027 GRA Period, NS Power may include prior FAM deferrals for certain rate classes (Large General, Medium Industrial, and Large Industrial) in order to save additional interest charges which would accrue by further deferring such amounts to the end of the 2026-2027 GRA Period.

4.0 FILING AND PROCEDURAL DEADLINES

Annual Filing Requirements for Fuel Adjustment Rider

For the years 2026 and 2027 NS Power will submit as required a Fuel Adjustment Mechanism Formula filing for the AA and BA, which shall provide a forecast of general system requirements and include a proposed calculation of the Fuel Adjustment Mechanism Formula for the upcoming year.

Annual Filing Requirements for Base Cost of Fuel Forecast

For each year in which NS Power applies to adjust the Base Cost of Fuel, a load forecast, Base Cost of Fuel and net system requirement forecast filing for the upcoming FAM year (January 1 - December 31) will be submitted. A Plexos run Base Cost of Fuel forecast update will be provided. The Board's decision on the Base Cost of Fuel for the succeeding year will take into consideration the fuel forecast update and any stakeholder comments on the update.

NS Power will use the standardized forecasting methods provided in Appendix "B". NS Power will submit the standard templates for all fuel related information, including the Fuel Forecast Standardized Filing consisting of Reports OE-1(A) to (Q) and Report OE- 12, as approved in the Board's Order dated May 15, 2007, in support of the Base Cost of Fuel forecast for the upcoming year. The inputs developed as part of the Fuel Forecast Methodology in Appendix B and any explanations and required supporting information will also be provided.

General Annual Filing Requirements

NS Power shall make standardized annual report filings in accord with the structure and templates provided in Appendix “C” on the first Business Day of the third month after the preceding year end.

Quarterly Filing Requirements

NS Power shall make standardized quarterly report filings in accord with the structure and templates provided in Appendix “C” on the first Business Day after the release of NS Power’s quarterly financial results. NS Power’s quarterly financial results are released in the second month after the preceding quarter end.

Monthly Filing Requirements

NS Power shall provide standardized monthly reports in accord with the structure and templates provided in Appendix “C” on the twenty-first day after the month end (or the next Business Day after the twenty-first day if the twenty-first day falls on a non-Business Day).

Changes to Reporting Information

No changes to the approved reporting templates, including but not limited to designation of information as confidential, shall be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

Suggested revisions to FAM documents will be submitted to Stakeholders for review and input.

5.0 AUDIT AND OVERSIGHT

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM hearing to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NS Power or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit during the 2026-2027 GRA Period as it deems appropriate. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NS Power's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period. Audits will normally cover two-year periods or such periods as determined by the Board.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power's procurement as described in the NS Power Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power's conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):

- Fuel and purchased power costs
- Review of overall operational availability and capacity factor for the generating fleet
- Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
- Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
- Review all Fuel and Purchased Power contracts executed by NS Power and NSPEMI for the period under review for prudence and for compliance with the Fuel Manual
- Review of NS Power's use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments

Prior to setting the final audit scope, the auditor shall meet with NS Power and interested stakeholders.

Timing of the Audit

Audits are expected to commence in February of every second year or at such time as directed by the Board. Final reports will normally be filed by July 2 of every second year or on such other date as directed by the Board. The final report will evolve from a draft report which is provided to NS Power and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

Confidentiality

By no later than seven (7) Business Days prior to filing of the final report with the Board, the auditor will provide the final report to NS Power for the purposes of reviewing for confidential information.

NS Power shall identify to the auditor any information in the report which NS Power wants held in confidence by the Board at least two (2) Business Days prior to the filing of the final report. Based on the confidential information identified by NS Power, the auditor will file with the Board a confidential version of the report and a public version of the report which redacts NS Power's confidential information.

Within three (3) Business Days of the filing of the final report with the Board, NS Power shall file a request with the Board for any information in the final report which NS Power wants held in confidence together with the reasons for the request.

Significant FAM Changes

Where, in the absence of a General Rate Application, an increase for any customer class of more than 10 percent compared with the rate payable in the prior year is caused by the application of the FAM procedures, the Board should consider appropriate measures to assist customers.

The Board will monitor the operation of the FAM closely and reserves the right to intervene in any circumstance where it believes an increase to a customer class is not acceptable or in the public interest and take such steps as it considers appropriate to assist such customers including deferring a part of the increase for collection in a future time period.

6.0 STAKEHOLDER REVIEW AND DISCOVERY

Monthly, quarterly and annual non-confidential and confidential reporting will be available for access and viewing. NS Power confidential reporting will be available electronically or in a confidential data room. A Confidentiality Agreement or undertaking will be required to access confidential information. NS Power's confidential electronic data cart will be maintained on a rolling basis with complete information related to transactions in place and accessible within 45 days of the transaction date. For the Base Cost of Fuel forecast update, all support documentation available will be provided (e.g. recommendations, evaluations, and confirmations).

The reporting templates identified in Appendix "C" and the standard fuel-related forecast templates for the Base Cost of Fuel will be accessible to stakeholders in an electronic format. The Board's secure document site will be utilized to access the monthly, quarterly and annual reports. Transactional information, copyright information, and all forecasting information not included in the reports will be available in NS Power's confidential electronic data cart.

In each hearing to adjust the Base Cost of Fuel, or to approve the AA and BA in a non-Base Cost of Fuel setting year, stakeholders shall have the opportunity (and access to information) to challenge NS Power's fuel costs, the implementation of the methodology, and the contents of the succeeding year's forecast, consistent with their current rights in General Rate Cases. Notwithstanding the foregoing, stakeholders shall not be precluded from reviewing prior years' actual results versus prior forecasts in addressing the propriety of the succeeding year's forecast.

7.0 DEFINITIONS

Actual Adjustment (Refund)/Recovery Rate – AA: is an Actual Adjustment which consists of the difference between fuel-related costs recovered from a rate class through the application of the base rates and the actual fuel costs incurred and allocated to the rate class as of the end of September of the prior calendar year. The actual fuel costs will include the same cost items as the Base Cost of Fuel.

Actual Amount ‘AA’ Received/(Refunded) current period: the amount of(over)/under recovery of fuel costs collected or refunded in the current period, a product of the ‘Actual Adjustment (Refund)/recovery Rate – AA’ and the ‘Actual Sales’ for the current period.

Annual Weighted Average Cost of Capital (WACC): A calculation of a company’s cost of capital in which each category of capital is proportionately weighted. All capital sources - common stock, preferred stock (if applicable), and debt are included in the calculation.

Audit: An independent, objective examination and evaluation of the accounts and records of or the performance and cost effectiveness of an organization.

Balance: The net of debits and credits for an account at the end of a reporting period.

Balance Adjustment (Refund)/Recovery Rate – BA: is a Balance Adjustment, expressed in cents per kWh, which accounts for any (over)/under recovery collections which have occurred as a result of prior adjustments.

Balance Amount Received/(Refund) current period: the amount of remaining (over)/under recovery collections which have occurred as a result of prior adjustments, that are collected or refunded in the current period, a product of the ‘Balance Adjustment (Refund)/Recovery Rate – BA’ and the ‘Actual Sales’ for the current period.

Base Cost of Fuel Component – BCF: is the Base Cost of Fuel per kWh (¢/kWh) included in NS Power's rates.

Business Day: is any day other than a Saturday, Sunday, or municipal, provincial or federal statutory holiday in Halifax, Nova Scotia.

Compliance Filing: A report filed by NS Power with the Board subsequent to a Decision. This report includes financial, cost of service, rates, and other information that may require revision from NS Power's original application in order to comply with the Board's Decision.

Estimated Sales for the Current Year: is a forecast of projected electricity sales for customer groups that are subject to the FAM Formula.

Export Sales Costs: are the costs to generate power to serve sales outside of NS Power's service territory of Nova Scotia.

Export Sales Recoveries: are the proceeds or revenues received from the sale of export power.

Export Sales Generation: are the MWh's generated to serve customers outside of Nova Scotia.

Fuel Costs Recovered Through Base Cost of Fuel Component: the fuel costs recovered through the Base Cost of Fuel component is the product of the current period's sales in GWh multiplied by the Base Cost of Fuel, then divided by 100.

Fuel for Generation: the fuel costs incurred with consumption of a commodity for the purpose of generating power.

General Rate Application: An application filed by NS Power with the Board requesting general changes to the rates and tariffs it applies to its customer classes. The 2026-2027

GRA Period refers to the period beginning January 1, 2026 and ending December 31, 2027 or to such time as determined by the NSEB.

GRLF Revenue: The revenue received from Generation Replacement and Load Following (GRLF) Rate billings.

GRLF Administration Costs: That portion of GRLF Revenue represented by the \$5/MWh adder of that tariff.

GRLF Requirements: The energy requirement of the Generation and Load Following (GRLF) Rate, including losses.

Net Generation by Fuel Type: a financial report produced out of Oracle showing the net generation, expressed in MWh, by facility and fuel type.

NSPEMI: NS Power Energy Marketing Inc., a wholly owned subsidiary of NS Power, formed to facilitate fuel and purchased power transactions in the United States.

(Over)/Under-Recovery Amount: variance (over/under) between actual fuel costs and those recovered through the Base Cost of Fuel component included in rates.

Prior Year's AA (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's 'AA' and 'BA' (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's Accumulated Interest: the interest accumulated over the previous year on the balance in the 'Balancing Account' to be recovered/refunded to or by the customer during the current year through the 'BA: (Refund)/Recovery Rate'.

Prior Years (Refund)/Recovery Amount Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment'.

Total Balance Account Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'.

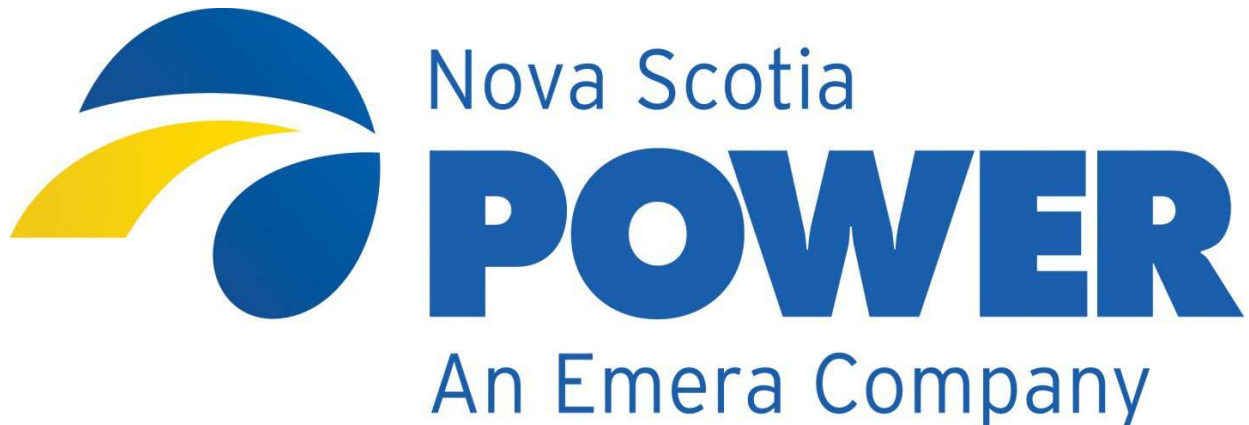
Total Purchased Power: the total cost of import, IPP and wind power purchases during the period used to serve the domestic load requirements.

Total System Requirements: the total sales and system losses expressed as GWh for domestic and export activity.

Two-Part Real Time Pricing Decremental and Incremental Charges: The credits paid to Extra Large Industrial Two-Part Real Time Pricing (ELI 2P-RTP) customers associated with decremental load (below the customer baseline load, CBL) or the additional charges to ELI 2P-RTP customers associated with load above the CBL.

Water Royalties: Amounts paid to government associated with environmental aspects of operating hydroelectric systems.

Nova Scotia Power Inc.												NSPI (FAM) A-13	
Annual FAM Reporting												CONFIDENTIAL	
Year 20XX													
Summary of Wind Curtailments													
Properties	January	February	March	April	May	June	July	August	September	October	November	December	Annual MWh
NSPI Owned Wind Generation ⁽¹⁾													
Non-NSPI Wind Generation													
Total Wind Generation													
Total Estimated Wind Curtailments													
Total Wind Curtailments as Percentage of NSPI Owned Wind Generation													
Total Wind Curtailments as Percentage of Non-NSPI Owned Wind Generation													
Total Wind Curtailments as Percentage of Total Wind Generation													
Notes													
(1) Includes all wind sites that NSPI has an ownership interest in (thus including South Canoe, Point Tupper, and Sable)													



**Fuel Adjustment Mechanism
Plan of Administration
in Effect for ~~2023~~2026-
20242027**

~~May 8~~XXXXXX~~April 25~~May
28, ~~2023~~2025

NS Power
FUEL ADJUSTMENT MECHANISM
PLAN OF ADMINISTRATION IN EFFECT FOR ~~2023-~~
~~2024~~2026-2027 May 8, ~~XXXXX~~ ~~2023~~2025

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Appendix A – Sample FAM Calculations

Appendix B – Forecasting Methodology

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~~Appendix D – FAM Regulatory Calendar (Stakeholder Engagement)~~

Appendix ~~E-D~~ – FAM Tariff

1.0 GENERAL DESCRIPTION

This document describes the plan for administering Nova Scotia Power Inc.'s (NS Power) Fuel Adjustment Mechanism (FAM), which was approved by the Nova Scotia Utility and Review Board (as of April 1, 2025 referred to as the Nova Scotia Energy Board (NSEB or Board)) in its decision letter issued on December 11, 2008. The FAM provides for the recovery of fuel and purchased power costs beginning January 1, 2009.

The Plan of Administration (POA) outlines the application and operation of the FAM. The Base Cost of Fuel will be calculated as set out in Section 2 "FAM COMPONENTS".

The Base Cost of Fuel can be reset in a General Rate Application (GRA), every second year as part of the FAM adjustment process, or as directed by legislation or an order of the Board. A forecast of costs and load for each test year will be used to set the Base Cost of Fuel. ~~During the 2023-2024 GRA Period, the Base Cost of Fuel is set below full recovery of the forecast costs over the two test years: 2023 and 2024.~~ The change in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the Cost of Service Study (COSS). ~~In addition, the under recovery balance from the prior fuel stability period of 2020-2022 will be deferred for recovery in future FAM AA/BA riders and there will be no FAM AA/BA rider in effect for 2023.~~

Stakeholders shall have the opportunity (and access to information) to challenge the implementation of the methodology and the contents of any forecast prior to its use in re-setting the Base Cost of Fuel. Both the implementation of the methodology and the forecasts will be the subject of a formal Board proceeding in which stakeholders will have their current rights as in general rate cases.

Stakeholders shall have the opportunity to challenge NS Power's fuel costs (and to secure access to information) at each annual or applicable hearing before the Board consistent with their current rights in general rate cases. The Board will also subject NS Power's FAM accounts to audits as per section 5.0 "Audit and Oversight" and as it deems appropriate.

The FAM will pass through the difference between actual costs and the Base Cost of Fuel to customers calculated on a ¢/kWh basis.

Interest will be added to all over/under-balance amounts and calculated at NS Power's Annual Weighted Average Cost of Capital (WACC).

The FAM will recover fuel cost changes resulting from over/under-recovery amounts, including an Actual Adjustment (AA) and a Balancing Adjustment (BA) for each rate class. The FAM adjustment is the difference between actual fuel cost and the Base Cost of Fuel) and will be calculated on a ¢/kWh basis.

2.0 FAM COMPONENTS

Each January 1 through December 31 period shall constitute a distinct FAM year. Under the FAM, an adjustment will normally be calculated once per year to reflect the over/-under recovery.

The FAM adjustment will consist of two components designed to provide for the recovery of fuel and purchased power costs. Those components are:

1. The Actual Adjustment Component (AA)
 - a. Established at a rate expected to recover the amount of the difference between the prior FAM year's actual fuel and purchased power costs and those recovered through the Base Cost of Fuel Component to the end of September of the prior year and October to December of the year before that, making 12 months of actuals.
2. The Balancing Adjustment Component (BA)
 - a. The Balancing Adjustment Component will provide for a correction to ensure that over/under-recovery produced by the Actual Adjustment Component is tracked and refunded to or recovered from customers.
 - b. The Balancing Adjustment Component may also include, subject to specific Board approval, deferrals of fuel and purchased power costs existing at the time of FAM adoption or that result from any future Board decision.

3.0 CALCULATION OF THE FAM RATE

NS Power's FAM is a forecasted base fuel rate operating on an annual cycle that includes an over/under recovery mechanism consisting of an Actual Adjustment (AA) and Balance Adjustment (BA).

The following formula will be used to determine the fuel adjustment factor (Fuel Adjustment Factor) for each upcoming FAM period:

Fuel Adjustment Mechanism Formula = AA + BA

Where:

1. AA is the Actual Adjustment that accounts for any differences between revenues collected through the application of the FAM during the previous one year period and actual Fuel Costs for each rate class (adjusted for the FAM incentive on an overall fuel cost basis) for the same one year period.

The AA rate is calculated for the following year on the basis of the over- or under-recovery of the Base Cost of Fuel at the end of September (year 1). Any over- or under-recovery from October to December will not be included in the rate calculation and will be deferred for recovery until the year subsequent to the following year (year 3). The actual AA starting balance for the following year (year 2) is the over- or under-recovery of the Base Cost of Fuel at the end of December (year 1).

2. BA is the Balance Adjustment that accounts for any over- or under-recovery amounts resulting from prior adjustments. The BA will also be the mechanism used to manage any deferred fuel and purchased power costs approved by the Board for inclusion in the BA.

The BA rate is calculated for the following year (year 2) on the basis of the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of September (year 1). The actual BA starting balance for the following year (year 2) is the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of December (year 1).

Appendix “A” to this Plan of Administration titled “Sample FAM Calculations”, provides a step by step detailed calculation of the overall Base Cost of Fuel, Actual Adjustment (AA), and Balancing Adjustment (BA) for a sequence of years starting in 2009. The applicable calculations illustrated in Appendix “A” will be used as outlined in the FAM Tariff in Appendix ~~ED~~.

Calculation of the Actual Adjustment Factor (AA) and Balancing Adjustment Factor (BA) FAM components will follow the fuel-related cost allocation methodology.

Actual (i.e. after the fact) fuel-related costs will be allocated in the same manner as the test year fuel-related costs used in setting base rates. In summary, this procedure will operate as follows:

1. A portion of the total fuel-related costs will be assigned to the following categories of non-FAM classes based on their fuel costing principles:
 - a. The below-the-line bundled service rates for Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power classes.
 - b. The Extra-Large Industrial Active Demand Control (ELIADC) class.
 - c. The unbundled tariffs: Open Access Transmission Tariff (OATT), ~~Wholesale Market Backup/Top-up Service Tariff (BUTU)~~, Energy Balancing Service Tariff (EBS), Renewable to Retail Market Transition Tariff (RTT).

- d. All remaining fuel-related costs will be allocated to ATL classes and the Wholesale Market Backup/Top-up Service Tariff (BUTU).
2. For ATL and BUTU classes, the following costs and credits
 - a. NS Power's plant fuel costs
 - b. costs of biofuels of purchased biomass generation costs
 - c. non-firm imports costs
 - d. export revenue credits

will be classified ~~as~~ 100 percent to energy ~~related and~~. ~~These costs will be~~ allocated to each class based on its relative contribution to monthly energy requirement.
3. Fuel costs assigned to the Wholesale Market Non-Dispatchable Supplier Spill Tariff ~~and Wholesale Market Backup/Top-up tariff~~ will be based on avoidable fuel costs.
4. Costs of Firm Imports and non-fuel portion of in-province Purchased Ppower and Import costs will be classified to demand and energy based on the load factor of the above-the-line classes. as follows.
 - a. ~~In province purchased power from wind generation will be segregated between Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). Their classification between energy and demand related services will reflect concurrent generation planning practice of NS Power. For the rate setting purposes of the 2026-2027/2023-2024 GRA Period the Company attributed to demand 18% of installed wind capacity of NRIS projects and 18% of ERIS projects.~~
 - b. ~~In province purchased power from biomass generation will be classified between energy and demand in the same proportion as classification of total~~

~~costs of the Port Hawkesbury biomass plant.~~

~~e. _____~~

~~d. _____ In province purchased power from all other sources than wind and biomass will be classified to demand and energy in the same manner as to NS Power's fixed cost base load generation.~~

e. ~~Maritime Link imports under Nova Scotia Block will be classified to energy and demand on the basis of the system load factor associated with the above-the-line (FAM) classes.~~

f.

g. ~~Non-firm imports will be all classified to energy.~~

h.

i.

a. The demand-related portion of the above costs will be allocated to each class based upon its relative coincident contribution to the three monthly system peaks (3CP) occurring in December, January and February. The energy portion of the above costs, ~~with the exception of the non-firm imports,~~ will be allocated to each class based on its relative contribution to monthly annual energy requirement. ~~Non-firm imports will be allocated to each class based on its relative contribution to monthly energy requirements.~~

b. In-province purchased power from biomass generation will be broken out between fuel and non-fuel components in the same proportion as that of the Port Hawkesbury biomass plant.

5. ~~Export revenues are allocated to ATL classes based on monthly energy requirements.~~

6.5. In order to ensure that allocated fuel-related costs are aligned with the revenue expected from approved rates for each class, the costs will be scaled up or down using the revenue-to-cost ratio (R/C ratio) for each class. The resultant costs by class will then be reconciled to the total ATL fuel-related costs based on their relative share of the total fuel costs.

7.6. The interest amount on the over- or under-recovery of fuel costs is apportioned to the individual rate classes at the end of the year on an annual basis using the

following approach:

- a. In a year where the interest amount owed to customers by NS Power at the end of September coincides with an over-recovery of fuel costs to the end of September in that year, or where the interest amount owed by customers to NS Power at the end of September coincides with an under-recovery of fuel costs to the end of September in the year, the interest amount will be apportioned to each class based on its relative share of the year-end fuel cost variance during that year.
- b. In a year where there is an interest balance owed to customers even though there has been an under-recovery of fuel costs to the end of September, or there is an interest balance owed to NS Power even though there was an over-recovery of fuel costs, NS Power will apportion the outstanding interest balance to each rate class on the basis of the relative class shares in the actual annual fuel cost incurred by NS Power.

The apportioned interest expense or credit is added to the fuel cost variance by class to provide the total fuel and interest (over)/under-recovery amount by class.

In order to determine the factor to be used as the Actual Adjustment (AA) component of the FAM, fuel-related costs allocated to each class in base rates will be subtracted from actual fuel-related costs allocated to each rate class. The difference in costs will be divided by the forecast energy sales (i.e. excluding line losses) to yield a credit or additional charge (in cents/kWh) that would normally be applied to customers' bills for the subsequent year. For the ~~2023-2024~~2026-2027 GRA Period, the AA/BA credit or charge (in cents/kWh) will be determined in ~~2026~~2023 for ~~2027~~2024 AA/BA riders. Any under/over recovered BCF amounts at the end of September ~~2026~~2023 will be used to determine the AA charge or credit for ~~2027~~2024.

The Balance Adjustment (BA) component of the FAM will be set to recover or

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refund any under or over-recovery due to prior adjustments. These adjustments may include variances in actual and forecasted sales volumes that were applied to the prior year AA that result in an under or over-recovery, any over- or under-recovered BCF amounts from October to December of the prior year, along with the associated interest component. The BA component may also capture other fuel-related factors subject to Board approval. ~~For the 2024 BA under recoveries that have been deferred from the prior fuel stability plan 2020-2022 will be included in the balance.~~

3.1 Treatment of load migrating ~~to~~between FAM/non-FAM classes

When a customer transitions some or all of its load ~~from a~~between FAM-class ~~to~~ and non-FAM classes, NS Power shall ~~treat~~determine the customer's ~~outstanding fuel cost imbalance at the date of transition~~migrating load in accordance with Special Condition 3 of the FAM Tariff. This determined imbalance will be adjusted in accordance with UARB decisions in subsequent FAM proceedings relating to the period in question (i.e. FAM AA/BA proceedings or a FAM Audit proceeding). The adjustments will be subject to UARB approval.

~~The outstanding balance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB. Where payment is made over time, the transitioning customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.~~

3.2 Allowable Fuel and Purchased-Power Costs

This section of the POA provides a framework for the fuel and purchased-power costs eligible for recovery through the FAM. Those costs will include allowable fuel expenses plus purchased-power expenses, less revenues from exported power and other fuel- and power-sale revenues.

Allowable fuel expenses will include normal, recurring, non-capital expenses that have been prudently incurred. Discrepancies between the value of measured fuel quantities and the book value of each fuel may also be included if those discrepancies are reasonably supported through surveys, tank level readings and pipeline reports. Exceptional or non-recurring costs appropriately classified as a fuel and purchased power cost will be brought to the attention of the Small Working Group for review for inclusion in the FAM.

NS Power understands that these costs are subject to audit, both internal and external, and to approval by the ~~Nova Scotia Utility and Review Board~~NSEB. Allowable Fuel and Purchased Power Costs will include the following items:

3.2.1 Natural Gas

- Natural Gas Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Pipeline Reservation Fees, Tolls, Penalties (such as imbalance charges)
- Pipeline Losses
- Natural Gas Storage Fees
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502050	REG FUEL GAS CONSUMED
502160	REG FUEL GAS SOLD
502100	REG FUEL GAS CONSUMED FX
502200	REG NATURAL GAS PIPELINE TOLL
502150	REG FUEL GAS CONSUMED COMMODITY DERIVATIVES
502170	REG FUEL GAS PIPELINE LOSSES
504410	REG GRID SALES FUEL NATURAL GAS CLEARING

504400 REG GRID SALES FUEL NATURAL GAS

3.2.2 Solid Fuel

Solid fuel costs are collected into three categories: Inventoried Costs, Costs Directly Applied, and Costs Expensed Through Plant Fuel Handling Adjustments. Those categories include the following costs:

- Inventoried costs
 - Commodity Costs - Coal, Petroleum Coke
 - Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
 - Third-party Quality Testing and Sampling
 - Transportation Costs (e.g. by rail, barge, vessel, truck etc.)
 - Includes loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
- Costs directly applied:
 - Third Party Fuel Handling, Transportation (e.g. movement between Long Term Dead Storage/Bear head and plants) and Maintenance related to Coal Piles
 - Storage fees (e.g. lease, handling fees, facility fees)
 - Environmental Compliance Fees (e.g. Provincial Air Emissions Fees)
 - Rail Car Costs (e.g. lease, repair, maintenance)
 - International Pier Operating & Maintenance Costs
 - Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)
- Costs expensed through the Plant Fuel Handling Adjustment:
 - At each thermal coal unit a demarcation point has been defined as the reclaim hoppers. Any solid fuel handling and transportation expenses up until the point of the reclaim hopper are considered a FAM expense. Costs will include the following items:

- NS Power labour and associated costs for Equipment Operators, Mechanics, Supervisors related to fuel handling and Lab Techs related to testing
- Costs associated with measurement of inventory (e.g. surveys, density testing)
- Non-capital materials for fuel handling (e.g. tools, replacement parts for machines)
- Repair costs for fuel handling equipment and infrastructure
- Heavy Equipment operating costs for fuel handling (e.g. rental and fuel)
- PTMT Pier Operating & Maintenance costs

Costs in all three Solid Fuel categories – inventoried, directly applied and expensed through plant fuel handling adjustments – are normally recorded in the following accounts in NS Power’s Chart of Accounts:

502250	REG FUEL COAL CONSUMED
502260	REG FUEL COAL CONSUMED IMPORT
502270	REG FUEL COAL CONSUMED DOMESTIC
502290	REG FUEL COAL CONSUMED OTHER
502280	REG FUEL COAL CONSUMED PETCOKE
502350	REG FUEL COAL CONSUMED FUEL TESTING
502300	REG FUEL COAL CONSUMED FX
504050	REG GRID SALES FUEL COAL CONSUMED

3.2.3 Heavy Fuel Oil

- HFO/Bunker Fuel Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Quality Testing and Inventory Measurement Costs

- Standby Emergency Response Services and third party compliance program
- Third Party Supervision of Unloading
- Transportation Costs (e.g. rail, barge, vessel, truck etc.)
 - This would include loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
- GHG Emission Compliance Program costs
- Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)
- Tufts Cove Wharf / Buoy Chain Inspection and Maintenance Costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502400	REG FUEL BUNKER C CONSUMED
502460	REG FUEL BUNKER C CONSUMED COMMODITY DERIVATIVES
502450	REG FUEL BUNKER C CONSUMED FX
504100	REG GRID SALES FUEL BUNKER C CONSUMED

3.2.4 Diesel Oil

- Diesel Commodity Consumed
- Transportation Costs
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502500	REG FUEL DIESEL OIL CONSUMED
--------	------------------------------

504450 REG GRID SALES FUEL DIESEL

3.2.5 Light Starter Oil

- LFO (Light Fuel Oil) Commodity Consumed
- Transportation Cost
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502550 REG FUEL LIGHT OIL CONSUMED

3.2.6 Fuel – Additives

- Additives - Ultramag, FireShield, etc.
- Transportation Costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502600 REG FUEL ADDITIVES CONSUMED
502650 REG FUEL LIMESTONE CONSUMED
504200 REG GRID SALES MERCURY SORBENT
504250 REG GRID SALES MERCURY SORBENT FX

3.2.7 Fuel – Limestone

- Limestone and related transportation
- Limestone Ash Hauling and Equipment Rentals
- Limestone Royalties
- Water Royalties

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

502650 REG FUEL LIMESTONE CONSUMED

3.2.8 Purchased Power

- Independent Power Producer (IPP) Purchases (e.g. Wholesale Market Non-Dispatchable Spill Tariff) IPP, ~~and~~ COMFIT production bonuses and penalties and costs associated with renewable energy programs (e.g. on bill credits for community solar programs).
- Community Feed in Tariff (COMFIT) Purchases
- Developmental Tidal Feed in Tariff (Tidal FIT) Purchases
- Import Power Purchases and associated fees (e.g. transmission tariffs and losses)
- Renewable Energy credits
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502700 REG PURCHASED POWER

502750 REG PURCHASED POWER FX

502800	REG PURCHASED POWER COMMODITY DERIVATIVES
502850	REG PURCHASED POWER IPP PRE 2001
502950	REG PURCHASED POWER COMFIT SMALL
502900	REG PURCHASED POWER IPP POST 2001
502710	REG PURCHASED POWER INADVERTENT
503050	REG PURCHASED POWER COMFIT LARGE
504300	REG GRID SALES PURCHASED POWER
502720	REG PURCHASED POWER NET METERING

3.2.9 Fuel Biomass

- Biomass Commodity Consumed
- Maintenance and Operating expenses for Fuel Handling (allocation between OM&G and FAM)
- Third Party Quality Testing and Inventory Measurement Costs (e.g. surveys, density testing, sampling)
- Storage fees (e.g. lease, handling fees, facility fees)
- Environmental Compliance including Silviculture Fees and harvest audits
- Transportation Costs (e.g. by barge, truck etc.)
- GHG Emission Compliance Program costs
- Ash Hauling costs (e.g. transportation, maintenance to ash hauling equipment, equipment rentals)

At the biomass plant a demarcation point has been defined as the bin collecting conveyor. Any fuel handling and transportation expenses related to steam for generation up until the point of the bin collecting conveyor are considered a FAM expense.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502380 REG FUEL BIOMASS CONSUMED

3.2.10 Fuel – Mercury Sorbent

- Additives – Powder Activated Carbon (PAC) and Calcium Chloride
- Transportation Costs
- Costs relating to a Hg (mercury) Diversion Program that has been approved by the Minister of Environment under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

504200 REG GRID SALES MERCURY SORBENT

504250 REG GRID SALES MERCURY SORBENT FX

3.2.11 Grid Sales Revenue

Revenue from power exports net of any transmission tariffs and losses. This includes Renewable Energy Credits arising out of the sale of renewable energy in the New England market.

3.2.12 Natural Gas Revenue

Revenue from the resale of natural gas.

3.2.13 Miscellaneous Revenue and Recoveries

Revenues from joint partnerships in wind farms (including the cost of NS Power's ownership which is applied to purchased power) and any other fuel-related miscellaneous revenues. These revenues include steam sales to Port Hawkesbury

Paper and steam sales at the Trenton Generating station.

The following accounts are normally used to record revenues from power exports and natural gas resales, revenues from joint partnerships in wind farms, and other miscellaneous revenues related to fuel.

417300	REG GRID SALES REVENUE
503200	REG NATURAL GAS REVENUE
503250	REG NATURAL GAS REVENUE FX
503300	REG WIND RECEIVABLES PURCHASED POWER
503350	REG WIND RECEIVABLES FUEL FOR GENERATION
535850	MISC REVENUE

These revenues will offset FAM-eligible fuel and purchased-power costs.

At times, revenues may be recorded as credits to related expense accounts, depending on their nature and applicable accounting guidelines. In these events, full explanations will be provided regarding why they were not offset against FAM-eligible fuel costs.

3.2.14 Foreign Exchange

All NS Power Fuel Accounts are subject to adjustments to record expenses or revenues denominated in foreign currencies and include the gain or loss on currency hedges entered into for the purpose of fuel procurement.

3.2.15 Limited-Duration Fuel Testing

These fuel testing costs (including solid fuel, liquid fuel and additives such as PAC) consist of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third party testing and analysis), and only to the extent incurred as part of limited duration test burns occasionally made by the Company. They shall be limited to non-capital costs and they shall be separately identified in

the Company's accounting records.

3.2.16 BTL Costs

- Spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff
- Fuel cost incurred in providing service under the Wholesale Market Backup/Top-up Service tariff, less revenue received under the Wholesale Market Backup/Top-Up Service tariff net of non-fuel items

3.2.17 GHG Emission Compliance Program Costs

- The cost of ~~emission allowances~~ (Fund eCredits) under the Nova Scotia ~~Cap and Trade program~~ and GHG Output Based Pricing System (OBPS) emissions compliance programs.
- Transaction fees for purposes of purchasing ~~or selling emission allowances~~ (GHG OBPS Fund eCredits).

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

503400 REG EMISSION ALLOWANCE EXPENSE

~~3.2.18 GHG Emission Compliance Program Revenue~~

- ~~• The revenue from the sale of emission allowances (credits) under the Nova Scotia Cap and Trade program or GHG emissions compliance programs.~~

~~Revenues of this type are normally recorded in the following account in NS Power's Chart of Accounts:~~

~~5XXXXX~~ ~~REG EMISSION ALLOWANCE REVENUE~~

3.2.18 NSP Owned Variable Production Costs

- Third party production bonuses and penalties for NSP owned power production.

3.3 Calculation of Fuel Costs

The fuel costs in the Base Cost of Fuel recovered through the FAM include allowable fuel and purchased power expenses (as noted in section 3.1 above) less revenues from exported power.

3.4 Deferrals

During the ~~2023-2024~~2026-2027 GRA Period, NS Power may include prior FAM deferrals for certain rate classes (Large General, Medium Industrial, and Large Industrial) in order to save additional interest charges which would accrue by further deferring such amounts to the end of the ~~2023-2024~~2026-2027 GRA Period.

4.0 FILING AND PROCEDURAL DEADLINES

Annual Filing Requirements for Fuel Adjustment Rider

~~In~~ For the years ~~2023-2026~~ and ~~2024-2027~~ NS Power will submit as required ~~by Appendix “D”~~ a Fuel Adjustment Mechanism Formula filing for the AA and BA, which shall provide a forecast of general system requirements and include a proposed calculation of the Fuel Adjustment Mechanism Formula for the upcoming year.

Annual Filing Requirements for Base Cost of Fuel Forecast

For each year in which NS Power applies to adjust the Base Cost of Fuel, a load forecast, Base Cost of Fuel and net system requirement forecast filing for the upcoming FAM year (January 1 - December 31) will be submitted ~~as per the schedule set out in Appendix “D”~~. A Plexos run Base Cost of Fuel forecast update will be provided ~~as per the schedule set out in Appendix “D”~~. The Board’s decision on the Base Cost of Fuel for the succeeding year will take into consideration the fuel forecast update and any stakeholder comments on the update.

NS Power will use the standardized forecasting methods provided in Appendix “B”. NS Power will submit the standard templates for all fuel related information, including the Fuel Forecast Standardized Filing consisting of Reports OE-1(A) to (Q) and Report OE- 12, as approved in the Board’s Order dated May 15, 2007, in support of the Base Cost of Fuel forecast for the upcoming year. The inputs developed as part of the Fuel Forecast Methodology in Appendix B and any explanations and required supporting information will also be provided.

General Annual Filing Requirements

NS Power shall make standardized annual report filings in accord with the structure and templates provided in Appendix “C” on the first Business Day of the third month after the preceding year end.

Quarterly Filing Requirements

NS Power shall make standardized quarterly report filings in accord with the structure and templates provided in Appendix “C” on the first Business Day after the release of NS Power’s quarterly financial results. NS Power’s quarterly financial results are released in the second month after the preceding quarter end.

Monthly Filing Requirements

NS Power shall provide standardized monthly reports in accord with the structure and templates provided in Appendix “C” on the twenty-first day after the month end (or the next Business Day after the twenty-first day if the twenty-first day falls on a non-Business Day).

Changes to Reporting Information

No changes to the approved reporting templates, including but not limited to designation of information as confidential, shall be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

Suggested revisions to FAM documents will be submitted to Stakeholders for review and input.

5.0 AUDIT AND OVERSIGHT

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM hearing to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NS Power or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit during the ~~2023-2024~~2026-2027 GRA Period as it deems appropriate. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NS Power's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period. Audits will normally cover two-year periods or such periods as determined by the Board.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power's procurement as described in the NS Power Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power's conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):

- Fuel and purchased power costs
- Review of overall operational availability and capacity factor for the generating fleet
- Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
- Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
- Review all Fuel and Purchased Power contracts executed by NS Power and NSPEMI for the period under review for prudence and for compliance with the Fuel Manual
- Review of NS Power's use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments

Prior to setting the final audit scope, the auditor shall meet with NS Power and interested stakeholders.

Timing of the Audit

Audits are expected to commence in February of every second year or at such time as directed by the Board. Final reports will normally be filed by July 2 of every second year or on such other date as directed by the Board. The final report will evolve from a draft report which is provided to NS Power and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

Confidentiality

By no later than seven (7) Business Days prior to filing of the final report with the Board, the auditor will provide the final report to NS Power for the purposes of reviewing for confidential information.

NS Power shall identify to the auditor any information in the report which NS Power wants held in confidence by the Board at least two (2) Business Days prior to the filing of the final report. Based on the confidential information identified by NS Power, the auditor will file with the Board a confidential version of the report and a public version of the report which redacts NS Power's confidential information.

Within three (3) Business Days of the filing of the final report with the Board, NS Power shall file a request with the Board for any information in the final report which NS Power wants held in confidence together with the reasons for the request.

Significant FAM Changes

Where, in the absence of a General Rate Application, an increase for any customer class of more than 10 percent compared with the rate payable in the prior year is caused by the application of the FAM procedures, the Board should consider appropriate measures to assist customers.

The Board will monitor the operation of the FAM closely and reserves the right to intervene in any circumstance where it believes an increase to a customer class is not acceptable or in the public interest and take such steps as it considers appropriate to assist such customers including deferring a part of the increase for collection in a future time period.

6.0 STAKEHOLDER REVIEW AND DISCOVERY

Monthly, quarterly and annual non-confidential and confidential reporting will be available for access and viewing. NS Power confidential reporting will be available electronically or in a confidential data room. A Confidentiality Agreement or undertaking will be required to access confidential information. NS Power's confidential electronic data cart will be maintained on a rolling basis with complete information related to transactions in place and accessible within 45 days of the transaction date. For the Base Cost of Fuel forecast update, all support documentation available will be provided (e.g. recommendations, evaluations, and confirmations).

The reporting templates identified in Appendix "C" and the standard fuel-related forecast templates for the Base Cost of Fuel will be accessible to stakeholders in an electronic format. The Board's secure document site will be utilized to access the monthly, quarterly and annual reports. Transactional information, copyright information, and all forecasting information not included in the reports will be available in NS Power's confidential electronic data cart.

~~Appendix "D" provides the generic regulatory calendar and hearing dates for the FAM processes which will be undertaken each year during the 2023-2024 GRA Period.~~

In each hearing to adjust the Base Cost of Fuel, or to approve the AA and BA in a non-Base Cost of Fuel setting year, stakeholders shall have the opportunity (and access to information) to challenge NS Power's fuel costs, the implementation of the methodology, and the contents of the succeeding year's forecast, consistent with their current rights in General Rate Cases. Notwithstanding the foregoing, stakeholders shall not be precluded from reviewing prior years' actual results versus prior forecasts in addressing the propriety of the succeeding year's forecast.

7.0 DEFINITIONS

Actual Adjustment (Refund)/Recovery Rate – AA: is an Actual Adjustment which consists of the difference between fuel-related costs recovered from a rate class through the application of the base rates and the actual fuel costs incurred and allocated to the rate class as of the end of September of the prior calendar year. The actual fuel costs will include the same cost items as the Base Cost of Fuel.

Actual Amount ‘AA’ Received/(Refunded) current period: the amount of (over)/under recovery of fuel costs collected or refunded in the current period, a product of the ‘Actual Adjustment (Refund)/recovery Rate – AA’ and the ‘Actual Sales’ for the current period.

Annual Weighted Average Cost of Capital (WACC): A calculation of a company’s cost of capital in which each category of capital is proportionately weighted. All capital sources - common stock, preferred stock (if applicable), and debt are included in the calculation.

Audit: An independent, objective examination and evaluation of the accounts and records of or the performance and cost effectiveness of an organization.

Balance: The net of debits and credits for an account at the end of a reporting period.

Balance Adjustment (Refund)/Recovery Rate – BA: is a Balance Adjustment, expressed in cents per kWh, which accounts for any (over)/under recovery collections which have occurred as a result of prior adjustments.

Balance Amount Received/(Refund) current period: the amount of remaining (over)/under recovery collections which have occurred as a result of prior adjustments, that are collected or refunded in the current period, a product of the ‘Balance Adjustment (Refund)/Recovery Rate – BA’ and the ‘Actual Sales’ for the current period.

Base Cost of Fuel Component – BCF: is the Base Cost of Fuel per kWh (¢/kWh) included in NS Power's rates.

Business Day: is any day other than a Saturday, Sunday, or municipal, provincial or federal statutory holiday in Halifax, Nova Scotia.

Compliance Filing: A report filed by NS Power with the Board subsequent to a Decision. This report includes financial, cost of service, rates, and other information that may require revision from NS Power's original application in order to comply with the Board's Decision.

Estimated Sales for the Current Year: is a forecast of projected electricity sales for customer groups that are subject to the FAM Formula.

Export Sales Costs: are the costs to generate power to serve sales outside of NS Power's service territory of Nova Scotia.

Export Sales Recoveries: are the proceeds or revenues received from the sale of export power.

Export Sales Generation: are the MWh's generated to serve customers outside of Nova Scotia.

Fuel Costs Recovered Through Base Cost of Fuel Component: the fuel costs recovered through the Base Cost of Fuel component is the product of the current period's sales in GWh multiplied by the Base Cost of Fuel, then divided by 100.

Fuel for Generation: the fuel costs incurred with consumption of a commodity for the purpose of generating power.

General Rate Application: An application filed by NS Power with the Board requesting general changes to the rates and tariffs it applies to its customer classes. The ~~2023-~~

~~2024~~2026-2027 GRA Period refers to the period beginning January 1, 202~~36~~7 and ending December 31, 202~~47~~7 or to such time as determined by the ~~NSUARB~~NSEB.

GRLF Revenue: The revenue received from Generation Replacement and Load Following (GRLF) Rate billings.

GRLF Administration Costs: That portion of GRLF Revenue represented by the \$5/MWh adder of that tariff.

GRLF Requirements: The energy requirement of the Generation and Load Following (GRLF) Rate, including losses.

Net Generation by Fuel Type: a financial report produced out of Oracle showing the net generation, expressed in MWh, by facility and fuel type.

NSPEMI: NS Power Energy Marketing Inc., a wholly owned subsidiary of NS Power, formed to facilitate fuel and purchased power transactions in the United States.

(Over)/Under-Recovery Amount: variance (over/under) between actual fuel costs and those recovered through the Base Cost of Fuel component included in rates.

Prior Year's AA (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's 'AA' and 'BA' (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's Accumulated Interest: the interest accumulated over the previous year on the balance in the 'Balancing Account' to be recovered/refunded to or by the customer during the current year through the 'BA: (Refund)/Recovery Rate'.

Prior Years (Refund)/Recovery Amount Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment'.

Total Balance Account Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'.

Total Purchased Power: the total cost of import, IPP and wind power purchases during the period used to serve the domestic load requirements.

Total System Requirements: the total sales and system losses expressed as GWh for domestic and export activity.

Two-Part Real Time Pricing Decremental and Incremental Charges: The credits paid to Extra Large Industrial Two-Part Real Time Pricing (ELI 2P-RTP) customers associated with decremental load (below the customer baseline load, CBL) or the additional charges to ELI 2P-RTP customers associated with load above the CBL.

Water Royalties: Amounts paid to government associated with environmental aspects of operating hydroelectric systems.

