2025 M12551

NOVA SCOTIA ENERGY BOARD

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

- and -

IN THE MATTER OF: **Nova Scotia Power's Application for 2026 Annually Adjusted Rates (AAR)**

INFORMATION REQUESTS

To: Nova Scotia Power Incorporated ("NS Power")

From: Renewall Energy Inc. ("**REI**")

Responses Due: December 22, 2025

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Issued at Halifax, Nova Scotia, this 1st day of December 2025.

Request IR-1:

Reference: **Section 2.0 Marginal Cost Analysis, pages 11-14.**

(a) Please provide the number of hours and percentage of hours for each of the years 2023, 2024 and 2025 year-to-date plus forecast that each generator class (e.g coal, natural gas, hydro, diesel, import, etc) was forecasted to be the marginal unit on the system in the PLEXOS model used in calculating NS Power's average annual marginal costs for the AARs. Please provide this information in tabular format disaggregated by generator type.

(b) For each of 2023, 2024 and 2025 to date and forecast to year-end, please provide the hours and percentage of hours of the year that each generation class was actually the marginal unit on the system. Please identify any material variances between forecast and actual, and provide explanations for variances exceeding 10%.

(c) For the 2026 forecast average annual marginal cost of $67.36/MWh calculation, please identify the % of hours in 2026 that each generation class is forecast to be the marginal unit on NS Power's system.

(d) Please confirm that Output-Based Pricing System (**OBPS**) compliance obligations are fully included in the marginal cost used in PLEXOS dispatch at their full economic value. If not fully included, please explain what costs are excluded and quantify the impact on marginal cost calculations.

Request IR-2:

Reference: Page 12, lines 7-9 and footnote 17.

The PLEXOS model used for the 2026 AAR forecast is the 2025 Q3 Fuel and Purchased Power Model.[17]

17 - 2025 PLEXOS AAR F&PP model is based on the 2024 Q3 forecast F&PP model, with updated system assumptions, including commodity pricing update as of 2024-08-16.

(a) In stating the above, is NS Power saying it ran its model in Q3 2025, but the system and pricing assumptions were as of August 2024? If not, please explain.

(b) If so, does NS Power have assumptions and pricing updates more current than last year?

(c) In forecasting new wind in 2026, what was the latest available information relied on by NS Power?

(d) Does NS Power agree that more current data is likely to lead to fewer mismatches between forecast and actual? If not, please explain.

(e) Why does NS Power not secure more recent data to make its assumptions and pricing updates closer in time to when it runs its model?

Request IR-3:

Preamble: Based on the principles of economic dispatch, and recognizing the influence of environmental legislation, REI expects that the highest variable cost generators would generally be: diesel combustion turbines (CTs); natural gas generation from Tufts Cove; and imports.

(a) Does NS Power agree? If not, please explain and identify the highest variable cost generators in order of merit, including the all-in variable cost per MWh for each generator inclusive of fuel, carbon costs, and OBPS compliance costs.

(b) Please provide, for the relevant PLEXOS model, the number of hours and percentage of total hours in which the three highest cost generators were forecast to be the marginal generator in 2024 and 2025 versus the actual number of hours and percentage they were the marginal cost generator. Please explain any material variances and their impact on marginal cost forecasting accuracy.

Request IR-4:

Preamble: In response to the Board's Directive comparing monthly Forecast-to-Actual NB imports, in Section 2.3, page 14, NS Power indicated that forecast accuracy can be assessed via FAM reporting.

(a) Please identify specifically where (which schedules, tables, and line items) the relevant data can be found in the FAM filings to assess the accuracy of forecast marginal cost vs actual by generator class on a monthly basis. If such data is not currently reported in the FAM, please explain why not and what additional reporting would be required.

(b) For the purpose of assessing forecast accuracy, should "Actuals" be compared against "Forecast" or against "Budget"?

Request IR-5:

Preamble: The Table below was compiled from the December FAM monthly reports (and October 2025 which is the YTD).

(a) Please confirm the accuracy of the data and identify the date of the "Forecast" and "Budget" each year.

(b) Please provide the missing information required to evaluate historical forecast accuracy regarding natural gas, diesel, import purchases, and Maritime Link.

	A	B	C	D	E	F	G	H
1	(millions of dollars)							YTD
2		dec	dec	dec	dec	dec	dec	oct
3	**Natural Gas**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
4	Actual	92.4	110.5	117.6	147.2	160.1	148.2	98
5	Forecast					161	142.9	
6	Budget	19.6	52.5	42.9	47.1	144.1	109.2	146.8
7	Full Year Budget							176.4
8								
9	**Diesel**							
10	Actual	1.6	1.9	2.3	8.2	6.8	7.1	7
11	Forecast					11.1	4.1	
12	Budget	0	0.8	1.1	0.2	11.7	11.3	3.8
13	Full Year Budget							5.1
14								
15	**Import Purchases**							
16	Actual	50.2	49.9	50.3	-11.9	59.8	98.2	97
17	Forecast					58	86	
18	Budget	62.4	56.9	106.9	99.6	42.8	143.1	110.9
19	Full Year Budget							135.5
20								
21	**Martime Link**							
22	Actual	107	138.6	149.5	157.1	162.6	-324.9	156.7
23	Forecast					162.8	-336.5	
24	Budget	164	144.5	164.4	161.9	166.8	164.8	167.2
25	Full Year Budget							200.6

Request IR-6:

Preamble: It is understood that the PLEXOS model relies on monthly on-peak / off-peak pricing for imports, which may be reasonable in aggregate but may not reflect actual market pricing during periods of high system demand across interconnected power systems.

(a) Where the forecast marginal generator is an import, has NS Power assessed the accuracy of these forecasts on a monthly and annual basis? If yes, please provide the results of such assessments for the past three years. If no, please explain why NS Power has not undertaken such analysis given the materiality of import costs to marginal cost calculations.

(b) Over the last three years, for each year, please provide:

(i) The forecast number of hours in which NB imports and ML imports (disaggregated) were expected to be the marginal cost generator; and

(ii) The actual number of hours in which NB imports and ML imports (disaggregated) were the marginal cost generator.

Request IR-7:

(a) Please confirm that NS Power currently has the capability to produce reliable monthly marginal cost forecasts with accuracy comparable to or better than its annual forecasts. If not, what specific additional changes or resources would be required to enable it to do so, and what would be the associated costs and implementation timeline?

(b) Please provide an assessment of the operational and administrative impacts, including one-time or ongoing costs, to move from annual to monthly marginal cost updates for the AARs.

(c) Has NS Power analyzed or modeled results comparing the accuracy of annual versus monthly marginal cost pricing for the AAR tariffs? Is it able to do so?

(d) Does NS Power agree that monthly marginal cost pricing would improve price signals to market participants, including LRSs, and better reflect actual system conditions? If not, please explain in detail why annual pricing provides superior price signals despite monthly variations in fuel costs, import prices, and system conditions.

(e) Does NS Power agree that monthly marginal cost pricing would allow NS Power to recover costs more closely aligned with actual system conditions and fuel costs, thereby reducing cross-subsidization between bundled service customers and RtR market participants? If not, please explain why annual averaging does not create cross-subsidization risks and provide quantitative analysis supporting this position.

Request IR-8:

Reference: Assumptions, page 11, Appendix A3 PCON; and Board-Directed Sensitivity Analyses, pages 12-13 and Appendix A6 PCON.

(a) NS Power has stated that higher SO2 emission limits have resulted in lower marginal costs. Please confirm the SO2 emissions associated with NS Power production in 2026, the applicable SO2 emission limits, and the remaining headroom under such limits.

(b) Please quantify the impact on marginal costs of the higher SO2 limits.

(c) Are the marginal costs for NS Power higher once SO2 limits are reached, and if so, by how much per MWh? Please provide the marginal cost curve showing the step change in costs as SO2 limits are approached and exceeded.

(d) With respect to the listed assumptions and Board-directed sensitivity analyses of commodity price volatility, unavailability of Muskrat surplus energy, and delays to wind, does NS Power agree that these are the three assumptions with the most risk of material variance from forecast? If not, please identify and rank the top five assumptions by risk of variance and potential impact on marginal costs, and explain why sensitivity analyses were not performed on all material risk factors.

(e) Please provide the surplus energy offered by Nalcor/NLH and accepted by NS Power in each year under the Energy Access Agreement historically, as compared to forecast.

(f) If the probability of zero Muskrat Surplus Energy being delivered is improbable, please quantify the probability distribution NS Power has assigned to various delivery scenarios. Would NS Power agree there is utility in running sensitivity analyses at 50%, 75%, 125% and 150% of forecasted Surplus Energy to better understand the range of potential impacts on forecasted marginal and average costs? If not, why not?

(g) Regarding the updated 2026 PHP CBL load, please confirm whether this reflects the Goose Harbour Lake wind farm.

(h) Please provide a sensitivity analysis showing the impact on marginal and average costs if PHP continues to receive service under the ELIADC through 2026 versus taking service under a to-be-filed successor tariff which may be above-the-line. Please quantify the potential revenue and cost impacts of each scenario.

(i) Does NS Power have any more up-to-date information regarding commercial operation dates of new wind generation than was included in the PLEXOS modeling? If yes, please provide the updated information and explain why it was not incorporated into the model. If no, when was the last update received and when is the next update expected?

(j) While NS Power conducts these sensitivity analyses, please confirm whether the results are incorporated into NS Power's marginal cost forecasts through probability-weighting or other methodologies, or whether they are simply informational. If they are not incorporated, please explain why NS Power does not use probabilistic forecasting methods to improve forecast accuracy.

Request IR-9:

(a) Please explain what financial and operational risks or benefits NS Power faces if it underestimates marginal costs in the AAR calculation versus the risks or benefits if it overestimates marginal costs.

(b) Please quantify these risks or benefits where possible and identify which customer classes bear the consequences of forecast errors in each scenario.

(c) With respect to the RtR market specifically, please explain whether there are any technical, operational, or regulatory impediments to calculating and updating marginal costs on a more frequent basis than annually (such as quarterly or monthly). If impediments exist, please identify and quantify them. If no impediments exist, please explain why NS Power has not proposed more frequent updates.

(d) If a true-up mechanism were implemented to reconcile forecast versus actual marginal costs, please explain how this would affect:

(i) the risks or benefits to NS Power identified in part (a) above;

(ii) the need for or benefit of more frequent marginal cost updates; and

(iii) the allocation of forecast risk between NS Power's bundled customers and RtR market participants.

Request IR-10:

(a) Without commenting on the merits, please outline in detail the steps required to calculate and implement an annual true-up mechanism under which a credit or debit is calculated and applied to the applicable tariffs impacted by the Marginal Cost based on the difference between Actual versus Forecast Marginal Cost and Average Annual Cost. Please include the timing of calculations, the process for Board approval, and the mechanism for flow-through to customers.

(b) Please compare to the end of year calculation performed for the ELIADC.

Request IR-11:

Reference: Renewable to Retail Market Tariffs, page 31 states "Estimates for the current scope of work referenced remain in the range of $6.4 million" and cites to M11874, N-4, NS Power (NSUARB) IR-1.

(a) Attachments 1 and 2 to NSUARB IR-1 include actuals to the end of September 2024. Please refile Attachments 1 and 2 with updated actuals to November 30, 2025 and updated estimates to complete. Identify any material variances by cost category (above 10%) and provide a detailed explanation for each variance, including whether such variances indicate systemic estimating issues.

(b) This work was the subject of a capital work order CI C0053699 identified as a subsequent submittal in the 2023 ACE Plan. In what quarter does NS Power plan to file this Capital Work Order?

Request IR-12:

Reference: Appendix F2, F3 and F4.

(a) For each cross-referenced document from the GRA, please provide the assigned NSEB exhibit number.

(b) Please provide a pdf version of each cross-referenced document and relevant tab from the cross-referenced document.

(c) Please explain why NS Power refused access to confidential information in this matter upon undertaking by REI when it granted such access in respect of the 2024 AARs under similar confidentiality undertakings. What specifically changed in NS Power's assessment of confidentiality risks or REI's status? If NS Power is willing to provide access subject to more limited redactions, please specify what information would be disclosed and what redactions would remain, with justification for each category of redacted information.

Request IR-13:

Reference: Energy Balancing Service Tariff, pages 31-32 and Appendix F2.

(a) Please compare the forecasted export sales for 2025 and 2026 and provide an explanation.

(b) Please explain how the transmission loss factor is calculated or determined.

(c) With respect to Figure 9, please add a column to show the percentage change for each component of the EBS compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Request IR-14:

Reference: Standby Service, page 34.

With respect to Figure 10, please add a column to show the percentage change for each component of the Standby Service Tariff compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Request IR-15:

Reference: Appendix F3, page 137 Standby Demand Charge Calculation.

(a) Please explain in detail the source and derivation of the Interruptible Service Credit, including the methodology, assumptions, and calculations used to determine the credit amount.

(b) As this Interruptible Service Credit was not part of the 2025 AARs (or prior years), please confirm whether this relates to the Pilot Interruptible Service in the RtR market.

(c) Please provide the Board order or tariff provision authorizing this credit and explain the rationale for its inclusion in the 2026 Standby Demand Charge calculation.

Request IR-16:

Reference: RtR Transition Tariff (RTT) – Annual Energy Cost Adjustment, page 35 and Appendix F4, page 138.

Preamble: This portion of the tariff considers differences between marginal fuel costs and average fuel cost to calculate the impact to NS Power from load migration to an LRS. LRS Forecasts are being provided to NS Power, and there is an increasing role of environmental costs and regulations in determining marginal costs, so REI believes closer scrutiny of the calculation of the Annual Energy Cost Adjustment is warranted

(a) Please confirm that NS Power considered REI’s forecasted market uptake in its load forecast and calculation of average and marginal costs for 2026. If not, please explain why REI's forecast was not considered and what load migration assumptions were actually used.

(b) If yes, please confirm that the calculation of the RTT Annual Energy Cost Adjustment properly accounts for REI's forecasted load migration and explain in detail how this is reflected in the calculation, including the specific line items and formulae affected.

(c) Please confirm whether NS Power’s comparison is of average fuel costs (accounting for load migration) compared to marginal fuel costs (also accounting for load migration). If this is not the correct characterization, please explain precisely what comparison is being made and provide the formulae used.

(d) Please provide a detailed analysis of an alternative approach by which NS Power calculates the comparison of average fuel costs to marginal costs *before* LRS load migration to determine the Annual Energy Cost Adjustment and the impact to NS Power of load migration to RtR. Please quantify the difference between the current methodology and this alternative approach for 2026.

Request IR-17:

(a) Under the current RTT framework, please confirm whether the Annual Energy Cost Adjustment would require NS Power to provide a credit to the RtR customer in circumstances where the Average Marginal Cost (or the average avoided cost of the departing load) exceeds the average system fuel cost paid by FAM customers. If not, please identify the specific tariff provision that would prevent such a credit.

(b) In such a situation where avoided costs exceed system fuel costs, would the full value of the difference be payable to the RtR participant, or are there any limitations, offsets, or adjustments that would reduce the credit amount? Please explain with reference to specific tariff provisions.

(c) Please indicate whether NS Power believes that any cap, limit, floor, or other constraint applies to the magnitude of the credit payable under the Annual Energy Cost Adjustment, whether such constraint is explicit or implicit in the tariff design.

(d) If NS Power believes a cap exists:

(i) Please identify the specific tariff provision, Board order, or Board approval that establishes such cap, and provide the history of how this cap was determined;

(ii) Quantify the maximum amount that could be payable to an RtR customer in a given year under the cap and explain how this amount was calculated.

(e) If NS Power believes no cap exists, please confirm that under the current tariff structure, the Annual Energy Cost Adjustment may result in an uncapped credit owed to the RtR customer when avoided costs exceed system fuel costs, and explain whether NS Power believes this outcome is consistent with the original policy intent of the RTT.

Request IR-18:

Reference: Annually Adjusted Energy Savings Credit, page 35, lines 12-17.

The Annually Adjusted Energy Savings Credit is designed to credit the LRS with any non-fuel energy-related cost savings arising from freed-up capacity on NS Power's system as a result of a departure of its bundled service load to the RtR market. The Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's bundled service. The Company does not project savings in this cost category and proposes that the current value of zero remains in effect in 2026.

Reference: RTT Demand Savings Credit, page 36, lines 17-23.

The Annually Adjusted Demand Savings Credit is designed to pass to the LRS any non-fuel demand-related cost savings arising from freed up capacity on NS Power's system because of the departure of its bundled service load to the RtR market. As is the case with the Annually Adjusted Energy Savings Credit, the Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's service. The Company does not project savings in this cost category and proposes that the current value of zero remain in effect in 2026.

(a) Please confirm the assumptions in 2026 regarding load transitioning from NS Power's bundled service to RtR, including the MW amount, customer class, load profile, and timing of transition.

(b) What specific assumptions were made regarding firm capacity contributions from third-party generators serving the RtR market, including the MW amount of firm capacity, the reliability standard applied, and how such capacity contributions were verified or validated?

(c) Please provide a copy of Robert Cary's Market Design White Paper, regarding avoided cost of ECR as filed in the original application for RTR approval.

(d) Where NS Power maintains it has an obligation to serve the RtR load even if such load is under contract with an LRS and to provide sufficient firm capacity plus a reserve to meet its own customer demand, RtR customer demand and municipal customer demand (N-30 GRA NSPI (REI) IR-6), please explain how or under what specific circumstances these two savings credits (Energy Savings Credit and Demand Savings Credit) would ever be given any value greater than zero. If there are no such circumstances, please explain the purpose of including these tariff components.

Request IR-19:

With respect to Figure 11, page 37, please add a column to show the percentage change for each component of the RTT compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Request IR-20:

Reference: Board Directive regarding Interruptible Service, p. 37.

(a) Please confirm that REI, in fact, provided a response to NS Power's proposed LRS – Interruptible Pilot Project Terms of Reference on November 7, 2025 and please provide a copy of REI's response.

(b) Please provide a copy of any subsequent response or communication from NS Power regarding REI's November 7, 2025 response, and notes of any discussions regarding Interruptible Service.

(c) The Terms of Reference contemplate the Interruptible Pilot Project will commence when approved by the NSEB. Please provide NS Power's best estimate of when the application for approval will be filed with the Board, including the expected hearing schedule.

(d) Does NS Power perceive any technical, operational, regulatory, or commercial impediments to the Interruptible Pilot Project being available for the winter 2026/2027 season? If yes, please explain each impediment in detail and what steps would be required to overcome them.