REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Energy Board

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

2026 Annually Adjusted Rates (AARs)

NS Power
Application

November 7, 2025

REDACTED

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1.0 INTRODUCTION

Nova Scotia Power Incorporated (NS Power, Company) requests approval from the Nova Scotia Energy Board (NSEB, Board) of the annually adjusted tariff rates (AARs) provided herein for 2026 (2026 AARs).

- Generation Replacement and Load Following Tariff (GRLF)
- One Part Real Time Pricing (1P-RTP) Tariffs
- Shore Power Tariff (SP)
- Wholesale Market Back-up/Top-Up Service Tariff (BUTU)
- Wholesale Market Non-Dispatchable Supplier Spill Tariff (Spill)
- Renewable to Retail Energy Balancing Service Tariff (EBS)
- Renewable to Retail Standby Service Tariff (SS)
- Renewable to Retail Market Transition Tariff (RTT)
- Extra-Large Industrial Active Demand Control Tariff (ELIADC)

In this Application, NS Power provides updates on prior AAR proceeding directives (Sections 1.1 and 1.2), outlines the marginal cost assumptions (Section 2.0), and presents proposed methodologies and rate adjustments for each Tariff (Sections 4.0 to 8.0).

Changes to transmission rate structures and fixed cost adders under the 1P-RTP and Shore Power tariffs are addressed in Sections 4.0 and 5.0. The proposed rates for the ELIADC Tariff reflect methodologies approved in prior Board decisions, and those provided in the Company's October 31, 2025 Compliance Filing in M12184, with updates detailed in Section 8.0.

The non-fuel cost components of the energy charges of all the AAR tariffs, other than the GRLF and ELIADC, are derived from the proposed 2026 Cost of Service Study (COSS) as agreed by

Customer Representatives who, along with NS Power, engaged in a collaborative process to reach consensus on a 2026-2027 General Rate Application[1] (GRA) proposed by NS Power.

1.1 Prior AAR Proceeding Directives

In its Orders dated March 20, 2024 (2024 AAR proceeding)[2] and March 25, 2025 (2025 AAR proceeding)[3], the Board issued several directives. The following lists the in-progress directives from these proceedings with reference to the sections where related updates are provided.

(1) "After the completion of the TVP Pilot Program's evaluation, NS Power is directed to work with stakeholders to develop a time varying pricing structure for the AARs"[4] – this is addressed in section 1.2.

(2) "In the 2026 AAR application NS Power shall provide sensitivity analyses of potential delays to wind resources scheduled to go into service in 2025 and 2026 and explain the applied assumptions"[5] – this is addressed in section 2.2.

(3) "In the 2026 AAR application, submit a review comparing the monthly forecasted New Brunswick imports to actual New Brunswick imports for the years 2021, 2022, 2023, 2024 and 2025. For any variances between forecast and actual imports of 10% or greater, NS Power will provide explanatory notes"[6] – this is addressed in section 2.3.

(4) "In the 2026 AAR application, fully explain the revised construct of the One Part Real Time Pricing Tariff that was reviewed with stakeholders"[7] – this is addressed in section 4.1.

[1] M12451 – NS Power, 2026-2027 General Rate Application. September 17, 2025.
[2] M11422 – Board Order (2024 AARs), 311444. March 20, 2024.
[3] M11989 – Board Order (2025 AARs), 319782. March 25, 2025.
[4] M11989 – Board Order (2025 AARs), page 2.
[5] M11989 – Board Order (2025 AARs), page 2
[6] M11989 – Board Order (2025 AARs), page 2.
[7] M11989 – Board Order (2025 AARs), page 2.

(5) "To review the issue of Municipal Electric Utilities selecting reciprocal and non-reciprocal billing arrangements no later than in the 2026 AAR application"[8] – this is addressed in section 6.3.

(6) "NS Power and Roswall are directed to explore ways in which interruptible customers may take service under the RTR Tariff and provide their recommendations in the 2025 AAR application"[9] – this is addressed in section 7.4.

1.2 Board Directive regarding Time-varying Pricing Structure for AARs

In the 2024 AARs (M11422) proceeding, the NSEB issued the following directive:

> In the 2023 AAR decision the Board noted that NS Power offered to develop on-peak and off-peak AARs after the TVP pilot is complete, and the Board was satisfied with this recommendation. The Board directed NS Power to work with stakeholders and provide it with a recommendation on how to introduce a TVP structure for the AARs in the 2024 application. Later in 2023, the Board agreed with NS Power to add an additional pilot year to the TVP program. If NS Power intends to delay a Board directed stakeholder consultation, it must request approval from the Board. The Board maintains its position that developing on-peak and off-peak AARs would be best after the TVP pilot and evaluation are complete, especially given the participation of commercial customers in the pilot. The Board directs NS Power to engage with stakeholders within three months of the completion and evaluation of the TVP pilot.[10] [emphasis added]

Following the Board's 2024 AAR Decision, the Company filed (on July 31, 2024) and received, on October 31, 2024, Board acceptance of the Year Three (2023/24) Time-varying Pricing (TVP) Pilot Evaluation Report.[11] In accordance with this 2024 AAR directive, NS Power conducted a review of the existing AAR Tariffs to determine which may be suitable for TVP consideration. On January 31, 2025, the Company distributed a memorandum to AAR Stakeholders outlining its planned approach for reviewing AARs' suitability for time-variable pricing and revisiting the

[8] M11989 – Board Order (2025 AARs), page 2.
[9] M11422 – Board Order (2024 AARs), page 2.
[10] M11422 – Board Decision (2024 AARs), 311354, page 4. March 5, 2024.
[11] M11823 – Board Decision, 316514. October 31, 2024.

methodology for the Fixed Cost Adder portion of One Part Real Time Pricing Tariffs (described in Section 4.1).[12] The Company received feedback on the TVP aspects of the letter in February 2025. On March 25, 2025, the Board issued its Decision on the 2025 AARs, which provided the following directive:

> In the 2023 AAR decision, the Board noted that NS Power offered to develop on-peak and off-peak AARs after the TVP pilot is complete, and the Board was satisfied with this recommendation. The Board directed NS Power to work with stakeholders and provide it with a recommendation on how to introduce a TVP structure for the AARs in the 2024 application. In 2024, the Board directed NS Power to add an additional pilot year to the TVP program. The Board maintains its position that developing on-peak and off-peak AARs would be best after the TVP pilot evaluation is complete. The Board directs NS Power to engage with stakeholders on developing on-peak and off-peak AARs following the completion of the TVP pilot evaluation.[13] [emphasis added]

Subsequently, in April 2025, NS Power experienced a cybersecurity incident, which led to an extension for filing the 2024/25 TVP Evaluation Report and a temporary suspension of the TVP Tariffs for 2025/26, as further described under Matter M12499. In accordance with the Board's direction, NS Power intends to re-initiate stakeholder engagement on the TVP structure for AARs once systems have been fully restored, TVP operations have stabilized, and evaluations of the pilot are complete. The Company will provide an update on this matter in its 2027 AAR Application.

[12] M11989 – Letter NSPI re: Update on Items Arising from 2024 and 2025 Annually Adjusted Rates Proceedings, 96671. January 31, 2025.
[13] M11989 – Board Decision (2025 AARs), 319292, page 6. March 25, 2025.

2.0 MARGINAL COST ANALYSIS

The average annual marginal cost forecast for 2026 used in determination of the GRLF, SP, Spill, EBS, and RTT is $67.36/MWh. This represents approximately a 24 percent decrease from the forecast marginal cost of $89.19/MWh approved for use in the 2025 AARs.

The forecast marginal cost was determined using the most recent forecast of the system load, adjusted for the exclusion of the load billed under the ELIADC Tariff.

The average annual marginal generation cost calculation is included in **Partially Confidential Appendix A2**.

2.1 Assumptions

In its Decision on the 2017 Annually Adjusted Rates, the Board directed as follows:

> As noted earlier, NSPI's future AAR applications are to include the main modelling assumptions used in determining the LF rate, and any potential beneficial impact of the Maritime Link. The application is also to include a high level analysis of year-over-year changes that support the reasonableness of the average annual marginal costs derived by PLEXOS, as well as evidence to justify splitting the annual administration cost of the BUTU/Spill tariffs on a 50/50 basis.[14]

The decrease in modeling output prices in 2026 as compared to 2025, is mainly driven by the sulphur dioxide (SO_2) Certificate of Variance (CoV)[15] with respect to SO_2 emissions limits in 2026 which were received from the Nova Scotia Department of Environment and Climate Change in Q1 of 2025. Additionally, forecasted pricing for solid fuel has generally decreased in 2026 relative to 2025.

[14] M08383, 2017 Annually Adjusted Rates, Board Decision letter, February 15, 2018.
[15] With respect to sulphur dioxide, the Provincial Government provided NS Power a certificate of variance under section 61 of the *Environment Act* affecting allowable sulphur dioxide emissions (SO_2) which gives NS Power flexibility to better align SO_2 emission limits with the introduction of renewable energy to Nova Scotia.

The components of the energy production cost changes are outlined in the table below.

Figure 1: Cost of Energy Generation

$/MWh by Gen. Source	2026 AAR	2025 AAR	Percent Change (%)
Solid Fuel	[redacted]		
Oil & Gas			
NB Imports			
ML Surplus			

In addition, in the 2019 AARs proceeding NS Power committed to providing a comparison of values associated with each assumption from the current and previous year's application and PLEXOS output reports.[16] The PLEXOS model used for the 2026 AAR forecast is the 2025 Q3 Fuel and Purchased Power Model.[17]

The modeling assumptions used in the PLEXOS model for the 2026 AARs are summarized in **Partially Confidential Appendix A3 and Confidential Appendices A4 and A5**.

2.2 Board Directed Sensitivity Analyses

In accordance with the Board's prior AAR directives, NS Power has run the following sensitivities on the marginal cost:

(1) Forward commodity market returns volatility of plus 1.5 standard deviations (+**1.5 σ**) for the following fuel prices: AECO, AGT, HFO, AP12, Mass Hub Off-Peak, and Mass Hub On-Peak.

[16] M08966, 2019 Annually Adjusted Rates, NS Power Reply Evidence, January 28, 2019, page 10, lines 8-12.
[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.

(2) Forward commodity market returns volatility of negative 1.5 standard deviations (**-1.5 σ**) for the following fuel prices: AECO, AGT, HFO, AP12, Mass Hub Off-Peak, and Mass Hub On-Peak.

(3) No Muskrat Falls surplus (market-priced) energy in 2026.

Since becoming commercially available in April 2023, NS Power has experienced significant improvement in the reliability of energy flows across the Labrador Island Link (LIL) and Maritime Link (ML). NS Power has received the energy owed since signing the Acceleration Agreement in August 2021 and has experienced steady-state operations since Q4 2024, with only minor outages and planned maintenance impacting deliveries of energy. Having reached the steady-state operation of LIL and ML assets, the scenario which contemplates no surplus energy flow in 2026 no longer has reasonable probability of occurring and as such it provides no discernible value. NS Power requests that the Board consider removing this scenario as a requirement in future AAR applications.

(4) Scenarios of delays to wind resources scheduled to go into service in 2025 and 2026.[18]

NS Power does not believe the 'no new wind' scenario to be indicative of a plausible outcome for 2026. These wind sites are proceeding as planned with some planned to start at the end of 2025. The timing of new wind resources coming online may vary from the forecast assumptions, with some coming online earlier and some later; however, NS Power believes that the 'no new wind' scenario does not have a reasonable probability of occurring. This scenario shows the conservative case of no additional wind on the system as a bookend scenario for consideration. In addition, the forecast, as developed in Q3 2025, reflects the latest available information reducing the likelihood of an alternate scenario from the anticipated full operation planned 2026 wind sites.

[18] M11989 – Board Order (2025 AARs), page 2

The results of the sensitivity analysis for items 1 to 4 are provided in **Partially Confidential Appendix A6.**

2.3 Board Directive regarding Comparison of Monthly Forecast-to-Actual New Brunswick Imports

In accordance with the Board's directive in the 2025 AARs,[19] a review comparing the monthly forecasted NB imports to actual NB imports is provided in **Confidential Appendix A7**. As a result of the cyber incident, NS Power is only able to provide the comparison for January 2025 to September 2025 currently. The Company also provides the following discussion for added context.

As discussed in NS Power's response to Consumer Advocate IRs as part of the 2025 AARs filing (M11989), NB Imports are modelled based upon the historical realized imports from the NB/ISONE market. PLEXOS is supplied with assumptions and constraints available at the time of preparation of the model run and forecasts NB Imports on an economical basis within the confines of the volumetric constraints which are based on average historical import levels. Actual import volumes will vary from forecast due to a number of factors including market conditions, pricing, NB generating fleet availability, and NB system conditions.

NS Power files Fuel Adjustment Mechanism (FAM) Reports with the NSEB, on a monthly basis. In the FAM monthly reports, NS Power discusses the drivers for variances on actuals compared to the FAM forecast for all Imports, and starting in 2023, comparison to NS Power's latest internal forecast. Explanatory notes can be found on tab M7 while tabs M1 and M6 state the variances. In addition, changes to overall generation mix for NS Power compared to forecast can be found in Figure 1 of the cover letter submitted as part of the monthly FAM reports.

[19] M11989 – Board Order (2025 AARs), page 2.

3.0 LOAD FOLLOWING PORTION OF THE GRLF TARIFF

The GRLF Tariff is available to customers who have their own generation of continuous capability, normally used to support the customer's own load, where the customer has signed an operating agreement with NS Power. The GRLF service has three separate components: Generation Replacement (GR), Optional Load Following (LF), and Spill. There are currently two customers taking service under the GRLF Tariff. One customer takes only the GR service while the other customer takes all three services.

The GR service is a back-up service provided on a best-efforts basis where the customer's generation is shut down for scheduled maintenance, forced outage or loss of fuel supply. The service is priced at NS Power's incremental cost of generation at the hour the energy is required by the customer, plus the 0.5 cent per kWh fixed cost adder for additional Operating and Maintenance costs, service charges and Administration & General compensation costs.

Optional LF service applies where the customer's process limitations affect the ongoing loading of the customer's own generator. The LF rate is an energy-only charge composed of the forecast average annual incremental cost of generation plus the 0.5 cent per kWh for additional Operating and Maintenance costs.

Spill Service consists of reception of surplus generation from the customer's generator by NS Power when the customer's hourly generation is in excess of the customer's load. As set out in **Figure 2** below, the proposed 2026 LF rate represents a decrease of 2.183 cents per kWh compared to that used in 2025. The proposed GRLF Tariff is provided in **Appendix A1** and the redline version is provided in **Appendix H**.

Figure 2: GRLF Tariff Energy Charge in Cents per kWh

	2025	2026	Variance
Incremental Cost of Generation			
Fuel Cost	8.919	6.736	(2.183)
Additional O&M costs	0.500	0.500	0.000
Energy Charge (cents per kWh)	9.419	7.236	(2.183)

4.0 ONE PART REAL-TIME PRICING TARIFFS

Consistent with its October 15, 2025 memorandum to AAR Stakeholders (Appendix J) on NS Power's Proposal for Methodological Changes to 1P-RTP Tariff, the Company proposes that starting in 2026, there will no longer be avoided fuel cost adjustment and that there will be two 1P-RTP Tariffs in effect.[20]

(1) One Part Transmission RTP Tariff; and
(2) One Part Distribution Voltage RTP Tariff.

Each of these two tariffs includes energy charges with two components: hourly marginal costs forecast 20 minutes ahead, and fixed costs adders, updated annually. The hourly marginal costs are determined in real time and are not subject to Board approval. Further discussion on the rationale for the removal of avoided fuel cost adders to the 1P-RTP Tariffs is provided in Section 4.1. The adders are designed to recover the non-fuel-related costs that would be incurred by NS Power in serving the eligible customers under each of the 1P-RTP tariffs.

Please note that due to the proposed methodological changes in the COSS, filed in the 2026-2027 GRA, there is no longer a cost breakdown between environmental and non-environmental categories available.[21]

The proposed fixed cost adders for 2026, compared by component to the 2025 adders, are shown in **Figure 3**. A redline version is provided in **Appendix H**.

[20] Currently there are three One Part RTP Tariffs in effect: (a) two transmission-based tariffs: 1P-RTP Extra High Voltage (EHV) and 1P-RTP High Voltage (HV), and (b) one distribution-based tariff: 1P-RtP Distribution Voltage. This change stems from the consensus Cost of Service Study (COSS), filed in the 2026-2027 GRA (M12451) which no longer provides a breakdown of transmission costs by the EHV and HV components.

[21] With the proposed simplification in classification of the non-fuel generation costs to be done entirely based on the system load factor, there is no longer a need for tracking the environmental costs in the COSS, which were determined by the amount of generation costs initially classified to energy on the basis of the Company's bookkeeping records.

Figure 3: 1P-RTP Tariff Charges by Voltage and Cost Components in Cents per kWh

	2025		2026		Variance	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
EHV						
Fixed Cost Adder	5.721	0.539	n/a	n/a	n/a	n/a
Fuel Cost Adjustment	2.704	0.253	n/a	n/a	n/a	n/a
Total	8.425	0.793	n/a	n/a	n/a	n/a
HV						
Fixed Cost Adder	6.205	0.796	n/a	n/a	n/a	n/a
Fuel Cost Adjustment	2.852	0.360	n/a	n/a	n/a	n/a
Total	9.058	1.156	n/a	n/a	n/a	n/a
Transmission						
Fixed Cost Adder	n/a	n/a	5.308	0.728	n/a	n/a
Fuel Cost Adjustment	n/a	n/a	0.000	0.000	n/a	n/a
Total	n/a	n/a	5.308	0.728	n/a	n/a
Distribution						
Fixed Cost Adder	8.151	2.364	10.008	3.573	1.857	1.209
Fuel Cost Adjustment	0.752	0.216	0.000	0.000	(0.752)	(0.216)
Total	8.903	2.580	10.008	3.573	1.105	0.993

The calculations for the 2026 Fixed Cost adder are provided in **Partially Confidential Appendix B2**. Please also refer to **Partially Confidential Appendix D** for usage determinants used in rate calculations in **Partially Confidential Appendix B2**.

Since August 2014, the Company has provided service under the HV RTP Tariff to a customer who migrated a portion of its interruptible load from the Large Industrial Interruptible Rider (LIIR). Consistent with the requirement under Special Condition (6) of the HV RTP Tariff, the

transitioned load remains interruptible. Starting with 2026, this load will continue to be served as interruptible under the Transmission RTP Tariff instead of High Voltage (HV) RTP Tariff.

4.1 Rationale behind Removal of Avoided Fuel Cost Adjustment

In its Decision on the 2025 AARs, the Board directed as follows:

> NS Power identified issues in forecasting the cost to serve One Part-Real Time Pricing Tariff customers under the current method due to the required reduction in air emissions and the increasing amount of non-dispatchable generation sources. NS Power adjusted the SO2 emissions limits in the model but does not consider this to be a reasonable long-term solution. NS Power proposed to find a new methodology based on the application of marginal system fuel costs and review this methodology with stakeholders in upcoming consultations on the TVP structure of the AARs. The Board directs NS Power to review the issue no later than in the 2026 AAR application.[22]

On January 31, 2025, the Company issued a memorandum to AAR Stakeholders outlining its approach to reviewing AARs for time-variable pricing (Section 1.2) and revisiting the Fixed Cost Adder methodology for 1P-RTP Tariffs. The memorandum (filed in M11422 and M11989) described that the current decremental load approach for estimating avoided fuel costs had become increasingly unreliable due to stricter air emissions limits and the growing share of non-dispatchable generation. NS Power sought feedback on its plan to propose an alternate methodology based on marginal system fuel costs in the 2026 AAR application. While feedback was received on the time-variable AAR aspect of the memorandum (as described in Section 1.2), no comments were provided on the proposed 1P-RTP methodology change.

On October 15, 2025, NS Power distributed a second memorandum requesting stakeholder feedback on proposed changes to the calculation of 1P-RTP Adders. This memorandum (**Appendix J**) outlined NS Power's plan to eliminate the avoided fuel cost adjustment, apply hourly marginal energy costs for energy charges, and include only non-fuel costs in the fixed cost

[22] M11989 – Board Decision (2025 AARs), page 6.

adders, and proposed future 1P-RTP adjustments be reviewed as part of GRAs. No stakeholder comments on the October 15 memorandum were received in regard to NS Power's proposed treatment.

Estimating the cost to serve 1P-RTP customers using the decremental load methodology has become volatile and unreliable due to the progressive tightening of air emissions constraints and the increasing proportion of non-dispatchable resources in the generation mix. Decreasing SO_2 air emissions limits heavily constrain the modeled generation dispatch. Consequently, any decremental load model without a corresponding adjustment in allowable SO_2 emissions results in avoided costs that reflect the emissions compliance costs more than fuel and purchased power costs. This issue is exacerbated by the disproportionate greenhouse gas (GHG) Output-based Pricing System (OBPS) compliance obligation associated with natural gas generation, which does not emit SO_2 and thus constitutes a large portion of the avoided generation cost under the current emission limits.

In view of the foregoing, NS Power has, in this Application, eliminated the adjustment for the projected imbalance in the recovery of the avoided fuel. Energy charges under these tariffs are proposed to be based on hourly marginal costs, and the fixed cost adders are proposed to include only non-fuel costs. In accordance with the Board's directive in the 2025 AARs proceeding (M11989), the Company has reviewed the issue with stakeholders through its January 31 and October 15, 2025 Memoranda, in advance of this Application.

Further, NS Power proposes that, subject to the Board's determination in the Matter, future adjustments to the 1P-RTP tariffs be set as part of General Rate Applications, rather than the AAR process, as is the case with the costing approach used for Open Access Transmission Tariff (OATT) and Renewable to Retail Distribution Tariff.

5.0 SHORE POWER TARIFF

Service under the Shore Power (SP) Tariff is a seasonal priority interruptible service, which starting in 2026 is proposed to be differentiated by two voltage levels: one transmission level, as opposed to two transmission levels used currently (Extra High Voltage (EHV) and High Voltage (HV)[23]) and one primary distribution.[24] It is available to seaports in Nova Scotia from April 1 to November 30. There is currently one customer subscribed to the SP Tariff, taking service at the distribution voltage level.

The voltage-based SP rates are flat energy charges, each with the following two cost components:

- The line-loss adjusted Fuel Cost component represents the average annual marginal fuel cost. This is the same fuel cost as used in the load forecast (LF).

- The Fixed Cost Adder component, drawn from the Cost-of-Service Study, reflects the non-demand related fixed costs. The fixed cost component employs the 2026 Cost of Service inputs, filed with the 2026-2027[25] GRA currently before the Board under M12451.

Please note that due to the proposed methodological changes in the COSS, filed in the 2026-2027 GRA, there is no longer a cost breakdown by the environmental and non-environmental categories available.[26]

The proposed SP rates represent a decrease compared to the current rates as seen in Figure 6. This is caused by decreases in both the marginal fuel cost and the embedded non-fuel cost. The decrease in the marginal fuel cost is discussed in Section 2.0. The decrease in the non-fuel costs is primarily

[23] This change stems from the consensus Cost of Service Study (COSS), filed in the 2026-2027 GRA which no longer provides a breakdown of transmission costs by the EHV and HV components.
[24] Refer to Appendix J2.
[25] M12451: 2026-2027 GRA SR-01 Att 02 PCON
[26] With the proposed simplification in classification of the non-fuel generation costs to be done entirely based on the system load factor, there is no longer a need, for tracking the environmental costs in the COSS, were determined by the amount of generation costs initially classified to energy on the basis of the Company's bookkeeping records.

due to change in the COSS methodology which is proposed to classify 100 percent of transmission costs to demand. Since Shore Power, as a priority interruptible service, is only responsible for the energy-related costs, no transmission costs are attributed to this rate class. The proposed energy charge components for 2026 compared to the 2027 rates are set out in **Figure 4**.

Figure 4: Shore Power Tariff Charges by Voltage and Cost Components in Cents per kWh

	2025	2026	Variance
EHV			
Fuel Cost	9.187	n/a	n/a
Fixed Cost Adder	3.919	n/a	n/a
Total	13.106	n/a	n/a
HV			
Fuel Cost	9.276	n/a	n/a
Fixed Cost Adder	4.130	n/a	n/a
Total	13.406	n/a	n/a
Transmission			
Fuel Cost	n/a	6.900	n/a
Fixed Cost Adder	n/a	2.516	n/a
Total	n/a	9.417	n/a
Distribution			
Fuel Cost	9.464	7.062	(2.403)
Fixed Cost Adder	5.461	4.064	(1.397)
Total	14.926	11.126	(3.800)

The calculations for the SP rates are provided in **Appendix C2**. The proposed SP Tariff is provided as **Appendix C1**. A redline version is provided in **Appendix H**. Please also refer to **Partially Confidential Appendix D** for energy requirement figures used in rate calculations in **Appendix C2**.

6.0 WHOLESALE MARKET TARIFFS

Two tariffs applicable to Wholesale Market participants are adjusted on an annual basis: the Back-up/Top-up (BUTU) Tariff and the Wholesale Market Spill (Spill) Tariff.

The BUTU Tariff provides optional backup/top-up service to customers taking energy under the OATT. The Spill Tariff is available for use by independent non-dispatchable electric generators serving customers taking service under the BUTU Tariff. Both tariffs are subscribed on a minimum 12 month, annually renewable basis.

Four wholesale customers, which are Municipal Electric Utilities (MEUs), have expressed an intention to take service under the BUTU Tariff in 2026 in conjunction with that portion of their energy requirement which will continue to be supplied by the Ellershouse Wind Farm. The remaining portion of their energy requirements will continue to be served under bundled service billed under the Municipal Tariff.[27] As part of the 2026-2027 General Rate Application[28] settlement plan, the MEUs have also been included as taking service under the Municipal Tariff in calculating the Municipal Tariff rates for 2026-2027. The 2026-2027 GRA includes the assumption that the MEUs will be served under the reciprocal billing arrangements contingent on application of a contract demand of 7.5 MW.

One non-dispatchable supplier[29] was approved for service under the Spill Tariff.

[27] As of the time of this application, the portion of MEUs' demand and energy to be served under the Municipal Tariff in 2026 has not been finalized, yet. MEUs are awaiting Board's decisions on the 2026-2027 GRA and 2026 AARs, which will set the Municipal and BUTU rates for 2026, before they decide on whether they will choose BUTU service under a reciprocal billing arrangement contingent on application of a contract demand (CD) of 7.5 MWs or under a non-reciprocal billing arrangement contingent on application of a CD of 22.4 MWs. Please refer to IG IR-1 (NSUARB M11989) for explanation of how CDs are determined based on MEUs' choice of billing arrangements under the BUTU Tariff).

[28] M12451: 2026-2027 General Rate Application

[29] Alternate Resource Energy Authority

6.1 Back-up/Top-up (BUTU) Tariff

The BUTU Tariff has three base cost rate components subject to approval in this Application: a Customer Charge, a Demand Charge, and an Energy Charge.

The BUTU Tariff filed in this Application follows the rate setting methodology in the Board's Order[30] arising from matter M09940, which provides as follows:

> The Board orders the following:
> (1) The application is approved, as amended by the Board. The revised Tariff is attached as Schedule A.
> (2) The amended Tariff rate will be phased-in over four years, as directed by the Board, with the effective date of the first rate adjustment being January 1, 2023.
> (3) NS Power is directed to update the FAM-based and non-FAM-based demand and energy-related pricing components of the BUTU once a new cost of service study, base cost of fuel, or general rate application is conducted, as applicable.

The 2026 submission marks the last year of the four-year phase-in in which the BUTU rates are deemed to be fully embedded cost based.

6.1.1 BUTU Customer Charge

The Customer Charge is set in advance of the rate year, based on the anticipated administration costs and the forecast number of customers' accounts to which the Company issues separate BUTU bills. Consistent with the Board's 2019 AAR Decision,[31] NS Power has calculated this charge on the basis of six accounts, three of which belong to one municipal customer.

[30] M09940 December 13, 2021.
[31] M08966, Board Decision on AARs for 2019, March 1, 2019.

As approved by the Board in the original proceeding to set these rates,[32] the BUTU Tariff and the Spill Tariff were each assigned 50 percent of the associated administration cost. In its 2019 AAR Decision, the Board issued the following directive:

> For 2019, NS Power is directed to use the 2018 amount of $47,761.86 adjusted by the proposed annual inflation rate of 2.8%.[33]

In its Decision on the 2021 AARs, the Board stated:

> KDC observed that the relevant rate of inflation to be used for the purposes of the administration charge used in the AARs should be periodically reviewed, and NS Power agreed. The Board notes that the previous Board directive regarding the rate to be used to increase the administration charge was a directive that only applied to that year's application. The Board expects that NS Power will reassess this rate annually and choose a more appropriate rate, if applicable.[34]

Consistent with this approach, NS Power applied a 3.25 percent escalator to determine the 2026 Customer Charge. As a result, the customer charge is proposed to increase from $401.58 to $414.63 per customer per month. Please refer to **Appendix E2** for the calculations for the Customer Charge.

6.1.2 BUTU Energy Charge

The proposed Energy Charge of 9.150 cents per kWh reflects the sum of two components:

- the FAM-based component of 6.984 cents per kWh, determined in the 2026 Base Cost of Fuel calculations in **Partially Confidential Appendix E4** (tab "BCF Allocation," cell AS31); and

[32] M00543 – Wholesale Market Backup/Top-up Service Tariff and Wholesale Market Non-Dispatchable Supplier Spill Tariff proceeding, MEUNSC/SRENA IR-1 and Multeese IR-6, October 24, 2008.
[33] M08966, 2019 Annually Adjusted Rates, Board Decision, March 1, 2019, page 4.
[34] M09898, 2021 Annually Adjusted Rates, Board Decision letter, page 7.

- the non-FAM-based component of 2.166 per kWh, as provided in **Appendix F2**.

With the 2026 BUTU rate representing the last of the four-year phase-in, the non-FAM rate components phase-in is now complete and therefore no adjustments are required in 2026.

Please refer to **Figure 5** for summary of rate components used in the phase-in calculations. As this is the final year of the phase-in, the 'Marginal Cost Methodology' column in the Figure below will not be provided in future applications.

Figure 5: BUTU Energy Charge Components in Cents per kWh

Energy Charge Components	2026		
	Marginal Cost Methodology	**Embedded Cost Methodology**	**Proposed Rates**
Energy-related Purchased Power and Fuel Cost	6.736	6.984	6.984
Energy-related Fixed Generation Cost	0.000	2.166	2.166
Total	**6.736**	**9.150**	**9.150**

6.1.3 BUTU Demand Charge

The proposed Demand Charge of $11.704 per kilowatt (kW) of billing demand reflects a sum of two components:

- the 2026[35] FAM-based component of $6.252 per kW, determined in the 2026 Base Cost of Fuel calculations in **Partially Confidential Appendix E4** (tab "BUTU Capacity Credit Calc," cell E6 and E7); and

- the non-FAM-based component of $5.452 per kW, determined in **Appendix F3**.

[35] 2026-2027 GRA: Attachment 2026-2027 GRA SR-01 Att 05 PCON

With the 2026 BUTU rate representing the last of the four-year phase-in, the non-FAM rate components phase-in is now complete and therefore no adjustments are required in 2026.

Please refer to **Figure 6** for a summary of rate components. As this is the final year of the phase-in, the 'Marginal Cost Based Methodology' column in the Figure below will not be provided in future applications.

Figure 6: BUTU Demand Charge Components in Dollars per kW of Billing Demand

Demand Charge Components	2026		
	Marginal Cost Based Methodology	Embedded Cost Methodology	Proposed Rates
Demand-related Purchased Power Cost	$0.000	$6.252	$6.252
Demand-related Fixed Generation Cost	$13.430	$5.452	$5.452
Total	**$13.430**	**$11.704**	**$11.704**

Please refer to **Partially Confidential Appendix E5** for the calculation of the Marginal Cost-based Demand Charge of $13.430 per kW. As this is the final year of the phase-in, marginal cost-based demand charge calculations will not be provided in future applications.

6.1.4 Proposed BUTU Rates

The proposed BUTU Tariff charges for 2026 are set out in **Figure 7**.

Figure 7: BUTU Tariff Charges

	2025	2026	Variance
Customer Charge ($/customer/month)	401.58	414.63	13.05
Energy Charge (cents per kWh)	10.577	9.150	(1.428)
Demand Charge ($/kW)	7.160	11.704	4.544

Please refer to **Appendix E3** for the comparison of the marginal-cost based rates to the embedded cost-based rates. As this is the final year of the phase-in, marginal cost-based demand charge calculations will not be provided in future applications.

The proposed 2026 BUTU Tariff is provided in **Appendix E1**. A redline version is provided in **Appendix H**.

6.2 Spill Tariff

The Spill Tariff has two components: an Administration Charge and an Energy Credit.

The Administration Charge is proposed to increase from the currently approved $2,409.46 to $2,487.77 per supplier, per month in 2026. NS Power has determined this Charge by applying a 3.25 percent escalator to the Administration Charge currently in effect. Please refer to **Appendix E2** for the supporting calculation. The Energy Credit is the Company's forecast average marginal energy cost as approved for use with the GRLF rate.

The proposed rates for 2026 and their comparison with 2025 charges are set out in **Figure 8**. The proposed Spill Tariff is provided in **Appendix E1**. A redline version is provided in **Appendix H**.

Figure 8: Spill Tariff Charges

	2025	2026	Variance
Administration Charge ($/supplier/month)	2,409.46	2,487.77	78.31
Energy Credit (cents per kWh)	8.919	6.736	(2.183)

6.3 Board Directive regarding Reciprocal and Non-reciprocal Billing

The Board provided the following directive in its Order, dated March 25, 2025, approving the 2025 AARs:

> To review the issue of Municipal Electric Utilities selecting reciprocal and non-reciprocal billing arrangements no later than in the 2026 AAR application[36]

The Company reviewed this matter with the Municipal Electric Utilities. The Settlement Agreement on the 2026-2027 GRA (M12451) contains a term reinforcing commitment of MEUs and NS Power to work collaboratively to resolve this matter.

> b) NS Power and the MEUs will work collaboratively and in good faith to determine and attempt to agree, by no later than December 1, 2025 on (1) the timeline by which the MEUs will pay NS Power the full amounts of outstanding fuel costs and Maritime Link Assessment costs, and (2) the implementation of the BUTU Tariff service arrangements in conjunction with service under the Municipal Tariff in 2025, 2026, and 2027.[37]

NS Power met with MEUs legal counsel and AREA general manger on October 16, 2025 to commence discussions around MEUs' right to exercise choice of reciprocal and non-reciprocal billing arrangements on annual basis as well as the billing method to be used by MEUs in 2026. The collaboration is ongoing.

[36] M11989 – Board Order (2025 AARs), page 2.
[37] M12451 – NSEB (NSPI) IR-001 Attachment 1. November 5, 2025.

7.0 RENEWABLE TO RETAIL MARKET TARIFFS

This AAR Application includes three Renewable to Retail (RtR) tariffs: the Energy Balancing Service (EBS) Tariff, Standby Service (SS) Tariff, and Renewable to Retail Market Transition Tariff (RTT). These tariffs cover supplemental generation services provided to Licensed Retail Suppliers (LRS). In addition, RtR customers are subject to payment of riders approved by the Board in separate rider proceedings as applicable.

On October 27, 2021, the Board approved an application by Renewall Energy Inc. (Renewall) for a Retail Supplier license to sell renewable low-impact electricity.[38] Under the terms described in Schedule A of the Board's Order, Section 71 identifies that if Renewall has not sold any renewable low-impact electricity under its license by December 31, 2024, it must apply to the Board demonstrating cause as to why the license should not be cancelled. Renewall submitted requests to the Board to extend its market entry on April 30, 2024, and again on November 1, 2024. On August 19, 2025, the Minister of Energy issued a conditional Power Purchase Agreement between Mersey River Wind Inc., and NS Power pursuant to section 4AA of the *Electricity Act* (now section 24), and in accordance with 7B of the *Prescribed Generation Facilities and Energy-Storage Projects Regulations*, to backstop the Mersey River Wind project. On September 24, 2025, Renewall wrote to the Board again, seeking to extend the deadline for first selling renewable low-impact electricity under its license to March 31, 2027. In all instances, the Board approved Renewall's request to extend its deadline for selling renewable low-impact electricity with the most recent deadline set to March 31, 2027.

In Renewall's September 24, 2025 extension request to the Board, Renewall described recent progress made in its efforts to enter the market and that construction on the Mersey River Wind Project is expected to begin soon. The Board accepted Renewall's submission that the Canadian Infrastructure Bank instructed Renewall to request a three-month extension as a contingency

[38] M10293 – Board Decision, 288061. October 27, 2021.

against unforeseen schedule delays and so the request to extend the deadline for selling renewable low-impact electricity to March 31, 2027 was approved.[39]

From a project execution perspective, NS Power has completed all business process and technical setup work possible at this stage, ahead of final commissioning and the commercial operation date (COD). The remaining work, including final system testing, onboarding, and training for the operational team can be effectively completed within a seven-month window prior to the start of retail sales. The Company will continue to work with the LRS to align the implementation work with the LRS' expected date of first retail sales. Estimates for the current scope of work referenced remain in the range of $6.4 million.[40]

The Company has calculated the RtR Tariff Administration Charges in accordance with past practice and based on near-term forecast annual administration costs. As activity in the RtR market increases, it is anticipated that the cost of administering the market to be recovered from the LRSs will increase. These costs include the recovery of costs incurred to date, deferred costs associated with the development of the RtR market, and capital and operating-related costs associated with the development and implementation of RTR billing systems.[41]

To the extent additional costs are incurred in 2026, these costs will be deferred by the Company for future recovery. The Company anticipates recovery under the tariff construct to start in 2027.

7.1 Energy Balancing Service Tariff

The Energy Balancing Service (EBS) Tariff is a mandatory tariff applicable to the LRS. EBS consists of delivery of top-up energy to RtR customers and receipt of surplus generation from qualifying generators. The service is required to be taken in conjunction with standby service under the SS Tariff so that the reliability of service to RtR customers is equivalent to that provided to NS

[39] M10293 – Board Amended Order, 324541. September 26, 2025.
[40] M11874, RTR Implementation Cost – Board IR 01.
[41] M11874: RTR Implementation Cost – Board IR-01.

Power's Bundled Service customers. The EBS Tariff has three rate components: the Administration Charge, the Energy Charge, and the Energy Credit.

The Administration Charge is applicable to each LRS' account and is set annually in advance of the rate year based on the anticipated administration costs and the forecast number of LRSs. The EBS Tariff operates on the assumption that the administrative charge per LRS account should approximate that of the BUTU Tariff.[42] Based on NS Power's proposed method for calculating the BUTU Customer Charge for 2026, described in Section 6.1.1, the Administration Charge in the EBS Tariff is proposed to be the same at $414.63 per month. As the Company gains experience with RtR Market processes and costs, it is expected the administration charges applicable to the Wholesale Market and RtR Market participants will diverge.

The Energy Charge is applicable to top-up energy and is made up of the following two components:

(1) Annually adjusted average annual marginal fuel cost.

(2) Fixed Cost Adder reflective of fixed energy-related generation costs updated concurrent with changes in base cost rates brought through GRAs.

The Energy Credit applies to spilled energy and is the same as the Fuel Cost component used under the Energy Charge above. The proposed EBS rate charges and credit for 2026 as compared to 2025 are set out in **Figure 9**.

[42] M06214, Exhibit N-23, NSPI (SWEB) IR-7, October 9, 2015.

Figure 9: Energy Balancing Service Tariff Charges

	2025	2026	Variance
Administration Charge ($/customer/month)	401.58	414.63	13.05
Energy Charge (cents per kWh)			
Fuel Cost (cents per kWh)	8.919	6.736	(2.183)
Fixed Cost Adder (cents per kWh)	3.264	2.166	(1.099)
Total Energy Charge (cents per kWh)	12.183	8.902	(3.281)
Energy Credit (cents per kWh)	8.919	6.736	(2.183)

The calculations for the proposed Energy Charge under the EBS Tariff are provided in **Appendix F2** RtR Energy Balancing Charge. The proposed EBS Tariff is provided in **Appendix F1**. A redline version is provided in **Appendix H**.

7.2 Standby Service Tariff

The Standy Service (SS) Tariff is a mandatory tariff applicable to LRSs for supplemental standby generation capacity service provided in combination with EBS under the EBS Tariff. The SS Tariff has two rate components: the Administration Charge and the Demand Charge.

The Administration Charge is applicable to each LRS' account and is set annually in advance of the rate year, based on the anticipated administration costs and the forecast number of LRS accounts. The charge is set at par with the Administration Charge under the EBS Tariff discussed above. The proposed Administration Charge for 2026 is therefore $414.63 per month.

The Demand Charge is determined by the demand-related costs of generation from the COSS conducted for the purpose of GRAs. The most recent COSS comes from the 2026 COSS[43], which gave rise to the Demand Charge under this rate. As such, the Company proposes that it be set for 2026 at $5.452 per month per kilowatt of monthly standby contract demand.

[43] M12451, NS Power 2026 Cost of Service Study: 2026 General Rate Application.

The proposed SS rate charges for 2026 as compared to 2025 are set out in **Figure 10**.

Figure 10: Standby Service Tariff Charges

	2025	2026	Variance
Administration Charge ($/customer/month)	401.58	414.63	13.05
Demand Charge ($/kW)	3.397	5.452	2.055

The calculations for the proposed Demand Charge under the SS Tariff are provided in **Appendix F3** RtR Standby Demand Charge. The proposed SS Tariff is provided in **Appendix F1**. A redline version is provided in **Appendix H**.

7.3 Renewable to Retail Transition Tariff

The RtR Transition Tariff (RTT) is designed to recover from the LRSs NS Power's embedded fixed costs and deferred costs (ordinarily recovered through bundled service rates) which are not otherwise recovered through other RtR tariffs. RTT has two rate components: the Energy Charge and the Demand Charge.

7.3.1 RTT Energy Charge

The RTT Energy Charge has three components: Fixed Cost Adder, Annually Adjusted Energy Savings Credit and Annual Energy Cost Adjustment.

The charge is designed to only apply to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the EBS Tariff. For the purposes of this 2026 AAR Application, the Company assumed, as in previous years, that 50 percent of RtR Market energy will represent displaced energy on NS Power's system as a result of direct deliveries from third party suppliers (that is, deliveries which are consumed in real time as opposed to spilled to NS Power's system).

7.3.1.1 Fixed Cost Adder

The Fixed Cost Adder component of the EBS Tariff is designed to recover the fixed energy-related generation costs of NS Power and is to be updated concurrently with changes in base cost rates brought through a GRA. It is the same rate component as used in the Energy Charge of the EBS Tariff. However, it is applicable to the LRS' displaced energy on NS Power's generation system by bundled service customers who transitioned their load to the RtR market, as opposed to the top-up energy billed under the EBS Tariff.

7.3.1.2 Annually Adjusted Energy Savings Credit

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.

7.3.1.3 Annual Energy Cost Adjustment

The Annual Energy Cost Adjustment is designed to ensure that FAM customers are not affected by changes in system fuel costs as a result of a reduction in NS Power's generation due to the departure of the bundled service customers to the RtR market. If the average avoided cost of departing load exceeds the average system fuel cost paid by the FAM customers, this adjustment will be a credit and thus a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost paid by the FAM customers, this adjustment will be a debit and thus an increase in the Energy Charge.

The 2025 component was a credit of 2.463 cents/kWh because the forecast 2025 marginal fuel cost of 8.919 cents/kWh was greater than the 2025 average system unit fuel cost of 7.688

cents/kWh before the fixed cost credit already accounted for under earnings adjustments above. The 2026 marginal fuel cost forecast, at 6.736 cents/kWh, is lower than the 2026 test year average system unit fuel cost charge of 7.881 cents/kWh, as proposed for recovery through the base fuel cost rates under the 2026-2027 GRA, so the 2026 Energy cost adjustment is a debit of 2.198 cents/kWh.

Please refer to **Appendix F4** for calculations related to this rate component.

7.3.2 RTT Demand Charge

The Demand Charge is made up of two components: the Demand Charge from the SS Tariff and the Annually Adjusted Demand Savings Credit.

As discussed in Section 7.2, the proposed 2026 SS Tariff Demand Charge is $5.452 per month per kilowatt of monthly standby contract demand.

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.

7.3.3 Proposed RTT Rates for 2026

The proposed RTT rate charges by components for 2026, as compared to 2025, are set out in **Figure 11**. The proposed RTT is provided in **Appendix F1**. A redline version is provided in **Appendix H**.

Figure 11: Renewable to Retail Transition Tariff Charges by Cost Components

Energy Charge by Components (cents per kWh)	2025	2026	Variance
Fixed Cost Adder from EBS Tariff	3.264	2.166	(1.099)
Annually Adjusted Energy Savings Credit	0.000	0.000	0.000
Annual Energy Cost Adjustment	(2.463)	2.198	4.660
Total	0.802	4.363	3.562

Demand Charge by Components ($/kW)	2025	2026	Variance
Demand Charge from Standby Service Tariff	3.397	5.452	2.055
Annually Adjusted Demand Savings Credit	0.000	0.000	0.000
Total	3.397	5.452	2.055

7.4 Board Directive regarding Interruptible Service in the RTR Market

The Board provided the following directive in its Order, dated March 20, 2024, approving the 2024 AARs:

> NS Power and Roswall are directed to explore ways in which interruptible customers may take service under the RtR Tariff and provide their recommendations in the 2025 AAR application.[44]

Since the Company's update in the 2025 AAR Application, NS Power proposed Terms of Reference for the interruptible service pilot to Renewall for review and comment on July 2, 2025. As of this date, NS Power has not received a response. This topic remains on the agenda for NS Power's monthly check-ins with Renewall.

The pilot, once fully structured and following approval of any associated tariff revisions by the Board, is intended to offer NS Power and stakeholders insights into the potential operation of the interruptible process within the RtR market.

[44] M11422 – Board Order (2024 AARs), page 2.

8.0 EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

The ELIADC Tariff establishes the framework under which Port Hawkesbury Paper (PHP) pays the forecast incremental cost to serve plus a contribution toward fixed system costs. Under the ELIADC Tariff, PHP also provides NS Power with operational control of PHP's load to optimize system-wide efficiency.

The Tariff presented in Appendix G1 of this Application incorporates amendments directed by the Board in its Decision on the ELIADC Third Term Application (M12184), which remain subject to final determination.[45] These amendments include:

- An increase in the minimum Fixed Cost Recovery (FCR) payment from $4/MWh to $5/MWh;
- The transfer of FCR from the Customer Baseline (CBL) Energy Charge to the CBL Adder (CBLA); and
- Expansion of annual and quarterly reporting requirements, including detailed tracking of load shifting benefits and cost deviations.

NS Power anticipates filing an application for a successor tariff prior to December 31, 2025. Accordingly, service under the ELIADC Tariff may be discontinued during the 2026 calendar year.

The pricing components of the ELIADC Tariff are:

- ELIADC Energy Charge (proposed for NSEB approval in this Application); and

[45] The Company submitted its M12184 ELIADC Third Term Compliance Filing on Friday, October 31, 2025, in accordance with the Board's Decision dated September 22, 2025.

- ADC Load Shifting Credit (calculated post-Tariff year by NS Power based on actual system benefits).

8.1 ELIADC Energy Charge

The annual ELIADC Energy Charge is calculated annually using the following formula:

ELIADC Energy Charge = [CBL Energy Charge = (CBL Cost – FCR)] + CLBA + VCC[46]

Where:

- "CBL Cost" represents NS Power's forecast annual incremental, non-capital costs to serve PHP at a levelized baseline load, inclusive of fuel, purchased power, line losses, variable operating costs, and FCR which is transferred to the CBL Adder as described in Section 8.1.2;

- "FCR" is the minimum fixed cost recovery of $5/MWh contribution of PHP toward NS Power's fixed system costs, a portion of which is included in the CBL Cost and fully transferred to the CBLA under the Tariff provisions;

- "CBL Energy Charge" is equal to the CBL Cost less the portion of the $5/MWh FCR transferred to the CBLA, in accordance with the forecast price thresholds set out in Tariff;

- "CBLA" incorporates the full $5/MWh FCR in accordance with the forecast price thresholds set out in the Tariff; and

- Variable Capital Charge ("VCC") represents a fixed charge to recover NS Power's incremental generation and delivery infrastructure costs required to serve PHP.[47]

[46] ELIADC Tariff, Appendix G1, page 3.

Figure 12: Calculation of ELIADC Energy Charge

Item	Description	2026 ($/MWh)
A	CBL Cost	73.60
B	FCR	3.75
C=A–B	**CBL Energy Charge**	**69.85**
D	CBL Adder	5.00
E	Variable Capital Cost	1.02
F=C+D+E	**ELIADC Energy Charge**	**75.87**

8.1.1 CBL Cost and CBL Energy Charge

As defined in Section 8.1, the CBL Energy Charge represents the average annual incremental non-capital cost (in $/MWh), net of FCR, to serve PHP's forecast load. For the 2026 Tariff year, the CBL Cost is $73.60/MWh, and the 2026 CBL Energy Charge is $69.85/MWh, (i.e. CBL Cost of $73.60/MWh, net of $3.75/MWh FCR transferred to the CBLA under the provisions of the ELIADC Tariff).

Modeling Assumptions for the calculation of CBL Cost are provided in **Confidential Appendix G2**, which provides information regarding the ELIADC Tariff, based on the incremental load analysis. ELIADC load is added to the base system load, to simulate the incremental costs to serve the load, and the two forecasts are compared to produce the data contained in **Confidential Appendix G2**.

8.1.2 CBL Adder

The CBL Adder is calculated in accordance with the methodology prescribed in the ELIADC Tariff and is designed to recover the minimum $5/MWh FCR.[48] The CBLA varies based on the forecast CBL Cost and the following forecast price thresholds:

[48] ELIADC Tariff, Appendix G1, pages 2-3.

- **If CBL Cost ≤ $56.75/MWh**: CBLA = 75% × (61.75 – CBL Cost)[49]

- **If CBL Cost > $56.75/MWh and < $61.75/MWh**: CBLA = [75% × (61.75 – CBL Cost)] + [FCR – (75% × (61.75 – CBL Cost))][50]

- **If CBL Cost ≥ $61.75/MWh**: CBLA = $1.25/MWh + [0 × (CBL Cost – 61.75)] + FCR to transfer of $3.75/MWh[51]

For the 2026 Tariff year, the CBLA is set at $5.00/MWh, reflecting the full recovery of the minimum FCR under the revised Tariff. This represents an increase from the 2025 CBLA of $1.00/MWh, attributable to the transfer of FCR from the CBL Cost, resulting in the CBL Energy Charge, net of FCR, and the full transfer of FCR to the CBLA, as shown in **Figure 13**.

Figure 13: CBL Adder

	2026 ($/MWh)
CBL Cost	**73.60**
Minus FCR	3.75
CBL Energy Charge	**69.85**
Constant (CBLA)	**1.25**
Plus FCR transferred from CBL Cost	3.75
Total CBLA	**5.00**

[49] When the forecast CBL Cost is at or under $56.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL Cost and $61.75/MWh. As the CBLA is equal to or more than the $5/MWh FCR, the FCR is fully included in the CBLA.
[50] When the forecast CBL Cost is more than $56.75/MWh and under $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is the differential between the $5/MWh FCR and the calculated CBLA of 75 percent of the difference between the forecast CBL Cost and $61.75/MWh. The FCR transferred from the CBL Cost is then added to the calculated CBLA to equal $5/MWh FCR.
[51] When the forecast CBL Cost is at or over $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is $3.75/MWh. The difference between the forecast CBL Cost and $61.75/MWh is assigned a value of zero, and the CBLA is calculated as $5/MWh FCR.

8.1.3 Variable Capital Charge

The ELIADC Energy Charge includes a Variable Capital Charge (VCC) for the cost of NS Power's incremental generation and delivery of electricity for PHP. It is calculated by comparing NS Power's generation fleet dispatch with and without PHP on the system.

In its application for the 2021 AARs, NS Power proposed to re-calculate and update the VCC annually, instead of setting it once for the term of the ELIADC tariff as originally designed.

In its Decision on the 2021 AARs, the Board provided:

> The Board accepts NS Power's proposal to update the VCC in the ELIADC annually.[52]

In its Decision on the 2024 AARs, the Board provided:

> The Board accepts NS Power's assertion that PHP's load isn't the only factor in setting the VCC. Unit starts have a degrading effect on the assets. To comply with emissions targets, the number of unit starts are now forecasted to increase to accommodate PHP's load on the system. NS Power claimed that its methodology is consistent with previous years. The Board agrees that the methodology is consistent with previous years as provided in the application's Appendix G3 ELIADC VCC Review For 2024 Rate, Unit Utilization – Utilization Factor Criteria. However, the Board notes the setting of the Utilization Factor (UF) appears to have changed without justification. The Board does not agree with the UF applied to the "with PHP" scenario modeled for Lingan-3. Comparing the information in Appendix G3 for 2024 to that in the same Appendix for 2023, there is no clear change to the Utilization Factor Criteria. The Board considers that the UF for Lingan-3 "with PHP" in 2024 is the same as it was in 2023, and therefore, the UF delta value for 2024 should be the same value as 2023. The Board disallows the application of the Sustaining Capital Delta for Lingan-3.

Partially Confidential Appendix G3 of this Application summarizes the changes in utilization with and without PHP on the system in 2026. The proposed revised VCC is $1.02/MWh for 2026.

[52] M09898, Board Decision letter, February 2, 2021, page 6.

Figure 14 provides the updated VCC of $1.02/MWh, compared with the 2026 figures.

Figure 14: Variable Capital Cost Calculation

Item	2026
PHP VC Cost	$787,508
PHP Load Est. (MWh)	774.46
Proposed PHP VC / MWh	$1.02

8.2 ELIADC Energy Charge Calculation

The ELIADC Energy Charge is composed of the CBL Energy Charge (i.e. CBL Cost net of FCR which is transferred to the CBLA, as described in Section 8.1), CBLA, and VCC.

Figure 15 presents the calculation of the 2026 ELIADC Energy Charge of $75.87/MWh. The proposed ELIADC Tariff is provided in **Appendix G1**. A redline version is provided in **Appendix H**. For clarity, both the proposed ELIADC Tariff (**Appendix G1**) and the redline ELIADC Tariff (**Appendix H**) include the amendments to the ELIADC Tariff as provided in the Company's October 31, 2025 Compliance Filing under M12184.

Figure 15: ELIADC Energy Charge

Energy Charge by Component	2026 ($/MWh)
CBL Energy Charge	69.85
CBLA	5.00
Variable Capital Cost	1.02
Total	**$75.87**

9.0 RELIEF SOUGHT

NS Power respectfully requests the following relief:

(1) Approval to remove the 'No Muskrat Falls surplus (market-priced) energy' sensitivity analysis as a requirement in future AAR applications.

(2) Approval of the Company's proposed changes to the 1P-RTP and Shore Power Tariffs as described in Sections 4.0 and 5.0.

(3) Approval of the following Tariffs for use in 2026:

- GRLF Tariff
- 1P-RTP Tariffs:
  - One Part Transmission Real Time Pricing Tariff
  - One Part Distribution Voltage Real Time Pricing Tariff
- Shore Power Tariff
- BUTU Tariff
- Spill Tariff
- Energy Balancing Service Tariff
- Standby Service Tariff
- Renewable to Retail Transition Tariff
- Extra-Large Industrial Active Demand Control Tariff

Clean versions of the proposed tariffs are provided in **Appendices A1, B1, C1, E1, F1, and G1**.

A redline version of each tariff showing the changes from the tariffs approved by the Board for 2026 is provided in **Appendix H**.

(4) The Company further requests the Board approve the discontinuation of the following Tariffs, effective January 1, 2026, in light of the replacement of these Tariffs with the One-Part Transmission Real Time Pricing Tariff:

- 1P-RTP Tariffs:
  - One Part Extra High Voltage Real Time Pricing Tariff
  - One Part High Voltage (HV) Real Time Pricing Tariff

SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

Generation Replacement Service – backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

Optional Load Following Service – energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

Spill Service – hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators."

Rate

Backup Service

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be 7.236 cents per kWh.

ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition 8, normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the

Company will exercise the automated control of the customer's load to interrupt the customer load.

(4) Following interruption, service may only be restored by the customer with approval of the Company.

(5) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(6) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia Energy Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected customer shall be notified.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Marginal Cost ($/MWh)			
2026	**Peak**	**Off-peak**	**All periods**
Jan	[redacted]		
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year	[redacted]		67.36

2026 Annually Adjusted Rates

Modelling Assumptions used in PLEXOS

The PLEXOS model used for the 2025 Annually Adjusted Rates forecast is based on the 2025 Q3 fuel and purchased power forecast model.

A list of updates for the 2025 Q3 fuel and purchased power model include:

Update number	Update Description
1.	Generation maintenance scheduled (GMS).
2.	Fuel and power prices.
3.	Coal blends, restrictions, emissions parameters, and volumes.
4.	Emission limits for SO2 updated.
5.	2026 Port Hawkesbury Paper (PHP CBL) load.
6.	ML surplus energy schedule.
7.	ML re-delivery energy schedule.
8.	NB market energy schedule.
9.	NB Power RFP energy removed.

Maritime Link Impacts

Approximately [redacted] of the total 2026 forecasted energy requirement is supplied by ML energy.

2026 Annually Adjusted Rates Confidential Appendix A4 has been removed due to confidentiality.

2026 Annually Adjusted Rates Confidential Appendix A5 has been removed due to confidentiality.

Sensitivity 1: Prices Adjusted Upwards (+1.5 σ)

System Marginal Cost ($/MWh)			
2026	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	70.45

Sensitivity 2: Prices Adjusted Downwards (-1.5 σ)

System Marginal Cost ($/MWh)			
2026	Peak	Off-peak	All periods
Jan	[redacted]		
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year			62.38

Sensitivity 3: ML Surplus Energy not included

System Marginal Cost ($/MWh)			
2026	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	73.31

Sensitivity 4: No New Wind

System Marginal Cost ($/MWh)			
2026	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year			73.31

2026 Annually Adjusted Rates Confidential Appendix A7 has been removed due to confidentiality.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): 5.308 ¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): 0.728 ¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 69 kV or higher and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer

will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): 10.008 ¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): 3.573 ¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 kV and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer

will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

1P-RTP ADDER CALCULATION

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.				Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.				% VARIANCE		
	ON-PEAK	OFF-PEAK	TOTAL	% Share/ Factors	ON-PEAK	OFF-PEAK	TOTAL	% Share/Factors	ON-PEAK	OFF-PEAK	TOTAL
RTP ADDER COMPONENTS BY THE COST FUNCTIONAL AREAS ADJUSTED FOR FUEL COST IMBALANCE IN CENTS PER KWH											
Transmission-connected											
Generation Costs	$0.07633	$0.00000			$0.04580	$0.00000			-40%		
Transmission Costs	$0.00788	$0.00788			$0.00719	$0.00719			-9%	-9%	
Customer Cost	$0.00004	$0.00004			$0.00009	$0.00009			114%	114%	
Total	**$0.08425**	**$0.00793**			**$0.05308**	**$0.00728**			**-37%**	**-8%**	
HV (Not Applicable starting in 2026)											
Generation Costs	$0.07901	$0.00000							-100.0%		
EHV Transmission Costs	$0.00958	$0.00958							-100.0%	-100.0%	
HV Transmission Costs	$0.00183	$0.00183							-100.0%	-100.0%	
Customer Cost	$0.00015	$0.00015							-100.0%	-100.0%	
Total	**$0.09058**	**$0.01156**							**-100.0%**	**-100.0%**	
3PH Distribution											
Adjusted Generation Costs	$0.06323	$0.00000			$0.06435	$0.00000			1.8%		
Transmission Costs	$0.00880	$0.00880			$0.01081	$0.01081			22.8%	22.8%	
HV Transmission Costs	$0.00203	$0.00203							-100.0%	-100.0%	
Distribution Costs	$0.01468	$0.01468			$0.02462	$0.02462			67.7%	67.7%	
Customer Cost	$0.00029	$0.00029			$0.00031	$0.00031			4.1%	4.1%	
Total	**$0.08903**	**$0.02580**			**$0.10008**	**$0.03573**			**12.4%**	**38.5%**	
RTP ADDER COST COMPONENTS IN CENTS PER KWH											
Transmission-connected											
O&M	$0.01496				$0.01538				2.8%		
Capital	$0.02561				$0.02086				-18.5%		
ROE	$0.01125				$0.00956				-15.1%		
Generation Costs	**$0.05182**				**$0.04580**				-11.6%		
O&M	$0.00110	$0.00110			$0.00191	$0.00191			73.9%	73.9%	
Capital	$0.00282	$0.00282			$0.00352	$0.00352			24.7%	24.7%	
ROE	$0.00143	$0.00143			$0.00176	$0.00176			22.9%	22.9%	
Transmission Costs	**$0.00535**	**$0.00535**			**$0.00719**	**$0.00719**			34.3%	34.3%	
Fixed Costs	**$0.05717**	**$0.00535**			**$0.05298**	**$0.00719**			-7.3%	34.3%	
Avoided Costs	$0.19937	$0.01866			$0.00000	$0.00000			-100.0%	-100.0%	
less: MC Revenue	$0.17233	$0.01613			$0.00000	$0.00000			-100.0%	-100.0%	
Fuel Cost Adj	**$0.02704**	**$0.00253**			**$0.00000**	**$0.00000**			-100.0%	-100.0%	
Customer Cost	**$0.00004**	**$0.00004**			**$0.00009**	**$0.00009**			113.9%	113.9%	
EHV	**$0.08425**	**$0.00793**			**$0.05308**	**$0.00728**			-37.0%	-8.1%	

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.		Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.		% VARIANCE	
HV (Not Applicable starting in 2026)						
O&M	$0.01561				-100.0%	
Capital	$0.02673				-100.0%	
ROE	$0.01175				-100.0%	
Generation Costs	**$0.05409**				-100.0%	
O&M	$0.00160	$0.00160			-100.0%	-100.0%
Capital	$0.00412	$0.00412			-100.0%	-100.0%
ROE	$0.00209	$0.00209			-100.0%	-100.0%
Transmission Costs	**$0.00781**	**$0.00781**			-100.0%	-100.0%
Fixed Costs	**$0.06190**	**$0.00781**			-100.0%	-100.0%
Avoided Costs	$0.18982	$0.02395			-100.0%	-100.0%
less: MC Revenue	$0.16130	$0.02036			-100.0%	-100.0%
Fuel Cost Adj	**$0.02852**	**$0.00360**			-100.0%	-100.0%
Customer Cost	**$0.00015**	**$0.00015**			-100.0%	-100.0%
HV	**$0.09058**	**$0.01156**			-100.0%	-100.0%
DISTRIBUTION VOLTAGE						
O&M	$0.01670		$0.02161		29.4%	
Capital	$0.02860		$0.02931		2.5%	
ROE	$0.01257		$0.01343		6.9%	
Generation Costs	**$0.05787**		**$0.06435**		11.2%	
O&M	$0.00178	$0.00178	$0.00287	$0.00287	61.4%	61.4%
Capital	$0.00457	$0.00457	$0.00529	$0.00529	15.8%	15.8%
ROE	$0.00232	$0.00232	$0.00265	$0.00265	14.1%	14.1%
Transmission Costs	**$0.00867**	**$0.00867**	**$0.010807**	**$0.01081**	24.7%	24.7%
O&M	$0.00241	$0.00241	$0.00561	$0.00561	133.0%	133.0%
Capital	$0.00917	$0.00917	$0.01391	$0.01391	51.6%	51.6%
ROE	$0.00310	$0.00310	$0.00510	$0.00510	64.5%	64.5%
Distribution Costs	**$0.01468**	**$0.01468**	**$0.02462**	**$0.02462**	67.7%	67.7%
Fixed Costs	**$0.08122**	**$0.02335**	**$0.09978**	**$0.03542**	22.9%	51.7%
Avoided Costs	$0.14419	$0.04145	$0.00000	$0.00000	-100.0%	-100.0%
less: MC Revenue	$0.13666	$0.03928	$0.00000	$0.00000	-100.0%	-100.0%
Fuel Cost Adj	**$0.00752**	**$0.00216**	**$0.00000**	**$0.00000**	-100.0%	-100.0%
Customer Costs	**$0.00029**	**$0.00029**	**$0.00031**	**$0.00031**	4.1%	4.1%
Distribution	**$0.08903**	**$0.02580**	**$0.10008**	**$0.03573**	12.4%	38.5%

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.			Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.			% VARIANCE		
Allocation of Fixed Costs of GENCO & WIRECO									
Generation									
OM&G									
Transmission-connected	$1,508,132		$1,508,132	$3,023,441		$3,023,441	100.5%		100.5%
HV (Not Applicable starting in 2026)	$1,454,265		$1,454,265	$0		$0	-100.0%		-100.0%
Distr. Class	$5,438,851		$5,438,851	$6,788,563		$6,788,563	24.8%		24.8%
Eligible Total	$8,401,247		$8,401,247	$9,812,004		$9,812,004	16.8%		16.8%
None Eligible Total	$126,907,390		$126,907,390	$133,505,274		$133,505,274	5.2%		5.2%
NSPI Total	**$135,308,637**		**$135,308,637**	**$143,317,278**		**$143,317,278**	5.9%		5.9%
Capital									
Transmission-connected	$2,582,047		$2,582,047	$4,101,549		$4,101,549	58.8%		58.8%
HV (Not Applicable starting in 2026)	$2,489,823		$2,489,823	$0		$0	-100.0%		-100.0%
Distr. Class	$9,311,767		$9,311,767	$9,209,249		$9,209,249	-1.1%		-1.1%
Eligible Total	$14,383,637		$14,383,637	$13,310,797		$13,310,797	-7.5%		-7.5%
None Eligible Total	$217,276,053		$217,276,053	$181,110,969		$181,110,969	-16.6%		-16.6%
NSPI Total	**$231,659,690**		**$231,659,690**	**$194,421,766**		**$194,421,766**	-16.1%		-16.1%
ROE									
Transmission-connected	$1,134,636		$1,134,636	$1,879,450		$1,879,450	65.6%		65.6%
HV (Not Applicable starting in 2026)	$1,094,109		$1,094,109	$0		$0	-100.0%		-100.0%
Distr. Class	$4,091,894		$4,091,894	$4,219,949		$4,219,949	3.1%		3.1%
Eligible Total	$6,320,639		$6,320,639	$6,099,399		$6,099,399	-3.5%		-3.5%
None Eligible Total	$95,478,188		$95,478,188	$82,990,377		$82,990,377	-13.1%		-13.1%
NSPI Total	**$101,798,828**		**$101,798,828**	**$89,089,776**		**$89,089,776**	-12.5%		-12.5%
Generation Total									
Transmission-connected	$5,224,815		$5,224,815	$9,004,440		$9,004,440	72.3%		72.3%
HV (Not Applicable starting in 2026)	$5,038,196		$5,038,196	$0		$0	-100.0%		-100.0%
Distr. Class	$18,842,512		$18,842,512	$20,217,760		$20,217,760	7.3%		7.3%
Eligible Total	$29,105,523		$29,105,523	$29,222,201		$29,222,201	0.4%		0.4%
None Eligible Total	$439,661,632		$439,661,632	$397,606,619		$397,606,619	-9.6%		-9.6%
NSPI Total	**$468,767,155**		**$468,767,155**	**$426,828,820**		**$426,828,820**	-8.9%		-8.9%
Transmission									
OM&G									
Transmission-connected	$110,660	$129,066	$239,726	$375,184	$404,401	$779,585	239.0%	213.3%	225.2%
HV (Not Applicable starting in 2026)	$149,235	$152,545	$301,780				-100.0%	-100.0%	-100.0%
Distr. Class	$578,707	$549,928	$1,128,636	$901,324	$849,086	$1,750,410	55.7%	54.4%	55.1%
Eligible Total	$838,602	$831,539	$1,670,141	$1,276,509	$1,253,487	$2,529,995	52.2%	50.7%	51.5%
None Eligible Total			$26,408,243			$34,423,928			30.4%
NSPI Total			**$28,078,384**			**$36,953,923**			31.6%
Capital									
Transmission-connected	$284,320	$331,612	$615,931	$691,500	$745,349	$1,436,849	143.2%	124.8%	133.3%
HV (Not Applicable starting in 2026)	$383,432	$391,936	$775,368				-100.0%	-100.0%	-100.0%
Distr. Class	$1,486,882	$1,412,941	$2,899,823	$1,661,226	$1,564,946	$3,226,172	11.7%	10.8%	11.3%
Eligible Total	$2,154,635	$2,136,488	$4,291,122	$2,352,727	$2,310,295	$4,663,021	9.2%	8.1%	8.7%
None Eligible Total			$67,851,156			$63,446,557			-6.5%
NSPI Total			**$72,142,278**			**$68,109,579**			-5.6%
ROE									
Transmission-connected	$144,559	$168,604	$313,163	$346,528	$373,512	$720,040	139.7%	121.5%	129.9%
HV (Not Applicable starting in 2026)	$194,952	$199,275	$394,227				-100.0%	-100.0%	-100.0%
Distr. Class	$755,989	$718,394	$1,474,383	$832,481	$784,232	$1,616,713	10.1%	9.2%	9.7%
Eligible Total	$1,095,500	$1,086,273	$2,181,773	$1,179,008	$1,157,744	$2,336,753	7.6%	6.6%	7.1%
None Eligible Total			$34,498,163			$31,794,605			-7.8%
NSPI Total			**$36,679,937**			**$34,131,358**			-6.9%
Transmission Total									
Transmission-connected	$539,539	$629,282	$1,168,820	$1,413,212	$1,523,262	$2,936,474	161.9%	142.1%	151.2%
HV (Not Applicable starting in 2026)	$727,619	$743,755	$1,471,375				-100.0%	-100.0%	-100.0%
Distr. Class	$2,821,578	$2,681,263	$5,502,841	$3,395,031	$3,198,264	$6,593,295	20.3%	19.3%	19.8%
Eligible Total	$4,088,736	$4,054,300	$8,143,036	$4,808,244	$4,721,526	$9,529,769	17.6%	16.5%	17.0%
None Eligible Total			$128,757,562			$129,665,091			0.7%
NSPI Total			**$136,900,598**			**$139,194,860**			1.7%

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.			Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.			% VARIANCE		
Distribution									
OM&G									
Eligible Total	$783,453	$744,492	$1,527,945	$1,761,469	$1,659,379	$3,420,848	124.8%	122.9%	123.9%
None Eligible Total			$36,484,514			$68,798,648			88.6%
NSPI Total			$38,012,458			$72,219,496			90.0%
Capital									
Eligible Total	$2,986,894	$2,838,358	$5,825,252	$4,369,210	$4,115,981	$8,485,191	46.3%	45.0%	45.7%
None Eligible Total			$139,096,329			$170,650,572			22.7%
NSPI Total			$144,921,581			$179,135,763			23.6%
ROE									
Eligible Total	$1,009,584	$959,378	$1,968,962	$1,602,463	$1,509,588	$3,112,051	58.7%	57.4%	58.1%
None Eligible Total			$47,015,205			$62,588,246			33.1%
NSPI Total			$48,984,167			$65,700,296			34.1%
Distribution Total									
Eligible Total	$4,779,931	$4,542,228	$9,322,158	$7,733,141	$7,284,948	$15,018,089	61.8%	60.4%	61.1%
None Eligible Total			$222,596,048			$302,037,466			35.7%
NSPI Total			**$231,918,206**			**$317,055,555**			36.7%
Total Cost Break-down by Category									
OM&G			$201,399,479			$252,490,698			25.4%
Capital			$448,723,549			$441,667,107			-1.6%
ROE			$187,462,932			$188,921,430			0.8%
Total			**$837,585,960**			**$883,079,235**			**5.4%**

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.	Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.	% VARIANCE
Fuel Cost Adjustment			
[redacted]			

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.				Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.				% VARIANCE		
Customer Admin Costs by Voltage Classes											
EHV											
Customers			2				8				300.0%
Average Cost per month			$400				$400				0.0%
Total	$4,431	$5,169	$9,600		$18,480	$19,920	$38,400		317.0%	285.4%	300.0%
HV (Not Applicable starting in 2026)											
Customers			6								-100.0%
Average Cost per month			$400								-100.0%
Total	$14,242	$14,558	$28,800						-100.0%	-100.0%	-100.0%
3PH											
Customers			39				39				0.0%
Average Cost per month			$400				$400				0.0%
Total	$95,765	$91,002	$186,767		$96,170	$90,597	$186,767		0.4%	-0.4%	0.0%
COST DETERMINANTS OF ELIGIBLE VOLTAGE CLASSES											
Sum of 3 Coincident Peak Contributions by eligible Voltage Classes											
Generation and EHV Transmission Systems											
EHV			76.0	1.11%			145.3	2.11%			91.3%
HV (Not Applicable starting in 2026)			73.2	1.07%							-100.0%
3PH			273.9	4.02%			326.3	4.74%			19.1%
None Eligible			6392.1	93.79%			6416.9	93.15%			0.4%
Total			6,815.3	100.00%			6,888.5	100.00%			1.1%
HV Transmission System											
HV (Not Applicable starting in 2026)			70.3	1.07%							-100.0%
3PH			263.0	4.02%							-100.0%
None Eligible			6,209.3	94.91%							-100.0%
Total			6,542.7	100.00%							-100.0%
Distribution System											
3PH			263.0	4.02%			303.2	4.74%			15.3%
None Eligible			6,279.7	95.98%			6,097.3	95.26%			-2.9%
Total			6,542.7	100.00%			6,400.5	100.00%			-2.2%

	Approved Year 2025 Exclude the GRLF, LRT and Shore Power rate classes.				Proposed Year 2026 Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.				% VARIANCE		
KWh Load by eligible voltage Classes											
Average Hourly KW Requirement											
EHV	24,870	26,424	25,683		48,727	47,829	48,257		95.9%	81.0%	87.9%
HV (Not Applicable starting in 2026)	23,198	21,602	22,362						-100.0%	-100.0%	-100.0%
3PH	82,739	71,627	76,924		79,130	67,909	73,258		-4.4%	-5.2%	-4.8%
MWh Sales per One MW of 3CP											
EHV	1,327	1,548	2,876		1,353	1,458	2,811		1.9%	-5.8%	-2.2%
HV (Not Applicable starting in 2026)	1,272	1,300	2,572						-100.0%	-100.0%	-100.0%
3PH	1,189	1,129	2,318		963	907	1,870		-19.0%	-19.7%	-19.3%
KWh Requirement											
EHV	103,855,103	121,129,585	224,984,688	20.6%	203,482,737	219,246,501	422,729,239	39.7%	95.9%	81.0%	87.9%
HV (Not Applicable starting in 2026)	96,873,237	99,021,544	195,894,781	17.9%					-100.0%	-100.0%	-100.0%
3PH	345,518,408	328,335,984	673,854,392	61.6%	330,446,776	311,294,898	641,741,674	60.3%	-4.4%	-5.2%	-4.8%
Total	546,246,748	548,487,113	1,094,733,861	100.0%	533,929,514	530,541,399	1,064,470,913	100.0%			
KWh Sales											
EHV	100,830,197	117,601,539	218,431,736	21.0%	196,618,713	211,929,809	408,548,522	40.1%	95.0%	80.2%	87.0%
HV	93,147,343	95,213,023	188,360,366	18.1%					-100.0%	-100.0%	-100.0%
3PH	325,602,942	309,410,903	635,013,845	61.0%	314,160,506	295,952,540	610,113,046	59.9%	-3.5%	-4.3%	-3.9%
Total	519,580,483	522,225,464	1,041,805,947	100.0%	510,779,220	507,882,348	1,018,661,568	100.0%			
% Line Losses											
EHV	3.0%	3.0%	3.0%		3.5%	3.5%	3.5%				
HV (Not Applicable starting in 2026)	4.0%	4.0%	4.0%		#DIV/0!	#DIV/0!	#DIV/0!				
3PH	6.1%	6.1%	6.1%		5.2%	5.2%	5.2%				
% Sales Split by TOU											
EHV	46.16%	53.84%	100.00%		48.13%	51.87%	100.00%		4.3%	-3.7%	0.0%
HV (Not Applicable starting in 2026)	49.45%	50.55%	100.00%						-100.0%	-100.0%	-100.0%
3PH	51.27%	48.73%	100.00%		51.49%	48.51%	100.00%		0.4%	-0.4%	0.0%
Customer Count											
Transmission-connected			2				8				300.0%
HV (Not Applicable starting in 2026)			6								-100.0%
3PH Class			39				39				0.0%
None Eligible			558,951				566,384				1.3%
Total			558,998				566,431				1.3%

Scenario A

		Monthly Hours in 2025			UNIT POWER PRODUCTION COSTS	RTP Avoided Costs											
		On	Off	Total	MC Ave	On	Off	RTP Ave Hourly KW Req On	Off	Total	RTPKWh Req On	Off	Total	Sales On	Off	Total
	Scenario A (2024)																
	Jan	368	376	744	[redacted]												
	Feb	320	352	672													
	Mar	336	408	744													
	Apr	352	368	720													
	May	352	392	744													
	Jun	336	384	720													
	Jul	368	376	744													
	Aug	336	408	744													
	Sep	352	368	720													
	Oct	368	376	744													
	Nov	320	400	720													
	Dec	368	376	744													
		4176	4584	8760													
	Scenario B: Monthly Hours in 2026																
		On	Off	Total													
1	Jan	352	392	744	[redacted]												
2	Feb	320	352	672													
3	Mar	352	392	744													
4	Apr	352	368	720													
5	May	336	408	744													
6	Jun	352	368	720													
7	Jul	368	376	744													
8	Aug	336	408	744													
9	Sep	352	368	720													
10	Oct	352	392	744													
11	Nov	336	384	720													
12	Dec	368	376	744													
		4176	4,584	8760													
	Jan	-4.3%	4.3%	0.0%	[redacted]												
	Feb	0.0%	0.0%	0.0%													
	Mar	4.8%	-3.9%	0.0%													
	Apr	0.0%	0.0%	0.0%													
	May	-4.5%	4.1%	0.0%													
	Jun	4.8%	-4.2%	0.0%													
	Jul	0.0%	0.0%	0.0%													
	Aug	0.0%	0.0%	0.0%													
	Sep	0.0%	0.0%	0.0%													
	Oct	-4.3%	4.3%	0.0%													
	Nov	5.0%	-4.0%	0.0%													
	Dec	0.0%	0.0%	0.0%													
		0.0%	**0.0%**	**0.0%**													

	Monthly Hours in 2025			RTP Revenue													KWh Requirement		
				Revenue									Unit Revenue			Adder as % of cost			
	On	Off	Total	On MC	Adder	Total	Off MC	Adder	Total	Total MC	Adder	Revenue Total	On	Off	All Hours	On	Off	Total	On	Off	Total
Scenario A (2024)																					
Jan	368	376	744	[redacted]															8,983,384	10,071,824	19,055,208
Feb	320	352	672																7,877,137	8,961,947	16,839,084
Mar	336	408	744																8,621,681	9,375,993	17,997,674
Apr	352	368	720																7,952,051	10,763,165	18,715,216
May	352	392	744																9,182,422	10,519,019	19,701,441
Jun	336	384	720																8,928,497	10,108,151	19,036,648
Jul	368	376	744																9,222,025	10,697,383	19,919,408
Aug	336	408	744																9,462,353	10,339,095	19,801,448
Sep	352	368	720																8,935,693	10,173,085	19,108,778
Oct	368	376	744																9,047,178	10,335,084	19,382,262
Nov	320	400	720																8,659,558	10,707,724	19,367,282
Dec	368	376	744																6,983,123	9,077,115	16,060,238
	4176	4584	8760																**103,855,103**	**121,129,585**	**224,984,688**
Scenario B:																					
	Monthly Hours in 2026																				
	On	**Off**	**Total**																		
Jan	352	392	744	[redacted]															18,743,940	19,288,323	38,032,262
Feb	320	352	672																16,474,532	17,585,124	34,059,656
Mar	352	392	744																15,086,706	18,759,554	33,846,260
Apr	352	368	720																16,066,756	16,945,276	33,012,032
May	336	408	744																18,211,397	18,153,433	36,364,830
Jun	352	368	720																16,447,406	18,885,069	35,332,475
Jul	368	376	744																18,563,631	18,697,161	37,260,792
Aug	336	408	744																18,419,759	19,547,752	37,967,511
Sep	352	368	720																16,555,833	18,561,560	35,117,393
Oct	352	392	744																17,745,175	17,179,850	34,925,025
Nov	336	384	720																16,505,809	18,021,750	34,527,559
Dec	368	376	744																14,661,793	17,621,650	32,283,443
	4176	4,584	8760																**203,482,737**	**219,246,501**	**422,729,239**
Jan	-4.3%	4.3%	0.0%	[redacted]															108.7%	91.5%	99.6%
Feb	0.0%	0.0%	0.0%																109.1%	96.2%	102.3%
Mar	4.8%	-3.9%	0.0%																75.0%	100.1%	88.1%
Apr	0.0%	0.0%	0.0%																102.0%	57.4%	76.4%
May	-4.5%	4.1%	0.0%																98.3%	72.6%	84.6%
Jun	4.8%	-4.2%	0.0%																84.2%	86.8%	85.6%
Jul	0.0%	0.0%	0.0%																101.3%	74.8%	87.1%
Aug	0.0%	0.0%	0.0%																94.7%	89.1%	91.7%
Sep	0.0%	0.0%	0.0%																85.3%	82.5%	83.8%
Oct	-4.3%	4.3%	0.0%																96.1%	66.2%	80.2%
Nov	5.0%	-4.0%	0.0%																90.6%	68.3%	78.3%
Dec	0.0%	0.0%	0.0%																110.0%	94.1%	101.0%
	0.0%	**0.0%**	**0.0%**																**95.9%**	**81.0%**	**87.9%**

EHV FUEL COST ADJUSTMENT

	Monthly Hours in 2025			Line Loss Factors			Average Hourly KW Requirement			Sales			MC Revenue			KWh Requirement			Line Loss Factors		
	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total
Scenario A (2024)																					
Jan	368	376	744	1.030	1.030	1.030	24,411	26,787	25,612	8,721,732	9,778,470	18,500,202	[redacted]			9,272,519	9,257,446	18,529,965	1.040	1.040	1.040
Feb	320	352	672	1.030	1.030	1.030	24,616	25,460	25,058	7,647,706	8,700,919	16,348,625				8,024,199	8,792,313	16,816,512	1.040	1.040	1.040
Mar	336	408	744	1.030	1.030	1.030	25,660	22,980	24,190	8,370,564	9,102,906	17,473,470				7,993,133	7,471,503	15,464,637	1.040	1.040	1.040
Apr	352	368	720	1.030	1.030	1.030	22,591	29,248	25,993	7,720,438	10,449,675	18,170,113				6,389,416	8,017,414	14,406,830	1.040	1.040	1.040
May	352	392	744	1.030	1.030	1.030	26,086	26,834	26,480	8,914,973	10,212,640	19,127,613				8,497,344	8,271,207	16,768,551	1.040	1.040	1.040
Jun	336	384	720	1.030	1.030	1.030	26,573	26,323	26,440	8,668,444	9,813,739	18,482,183				8,359,955	7,743,743	16,103,698	1.040	1.040	1.040
Jul	368	376	744	1.030	1.030	1.030	25,060	28,450	26,773	8,953,423	10,385,808	19,339,231				8,286,056	8,596,423	16,882,480	1.040	1.040	1.040
Aug	336	408	744	1.030	1.030	1.030	28,162	25,341	26,615	9,186,751	10,037,956	19,224,707				8,714,314	8,062,525	16,776,839	1.040	1.040	1.040
Sep	352	368	720	1.030	1.030	1.030	25,385	27,644	26,540	8,675,430	9,876,782	18,552,212				7,831,324	8,157,898	15,989,222	1.040	1.040	1.040
Oct	368	376	744	1.030	1.030	1.030	24,585	27,487	26,051	8,783,668	10,034,062	18,817,730				8,093,543	7,712,840	15,806,384	1.040	1.040	1.040
Nov	320	400	720	1.030	1.030	1.030	27,061	26,769	26,899	8,407,338	10,395,848	18,803,186				8,310,264	8,245,074	16,555,339	1.040	1.040	1.040
Dec	368	376	744	1.030	1.030	1.030	18,976	24,141	21,586	6,779,731	8,812,733	15,592,464				7,101,168	8,693,156	15,794,324	1.040	1.040	1.040
	4176	4584	8760	**1.030**	**1.030**	**1.030**	**24,870**	**26,424**	**25,683**	**100,830,197**	**117,601,539**	**218,431,736**				**96,873,237**	**99,021,544**	**195,894,781**	**1.040**	**1.040**	**1.040**
Scenario B:																					
	Monthly Hours in 2026																				
	On	**Off**	**Total**																		
Jan	352	392	744	1.035	1.035	1.035	53,250	49,205	51,119	18,107,019	18,639,373	36,746,391	[redacted]			-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Feb	320	352	672	1.035	1.035	1.035	51,483	49,958	50,684	15,914,162	16,991,841	32,906,003				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Mar	352	392	744	1.035	1.035	1.035	42,860	47,856	45,492	14,577,683	18,133,888	32,711,571				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Apr	352	368	720	1.035	1.034	1.034	45,644	46,047	45,850	15,529,837	16,386,254	31,916,091				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
May	336	408	744	1.035	1.034	1.035	54,201	44,494	48,877	17,598,749	17,550,342	35,149,091				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Jun	352	368	720	1.035	1.034	1.035	46,726	51,318	49,073	15,893,599	18,256,913	34,150,512				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Jul	368	376	744	1.035	1.034	1.035	50,445	49,726	50,082	17,940,188	18,075,252	36,015,440				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Aug	336	408	744	1.035	1.034	1.035	54,821	47,911	51,032	17,801,249	18,898,792	36,700,041				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Sep	352	368	720	1.035	1.035	1.035	47,034	50,439	48,774	15,998,506	17,942,161	33,940,667				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Oct	352	392	744	1.035	1.034	1.035	50,412	43,826	46,942	17,147,547	16,609,383	33,756,931				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Nov	336	384	720	1.035	1.035	1.035	49,124	46,932	47,955	15,948,264	17,419,947	33,368,211				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
Dec	368	376	744	1.035	1.035	1.035	39,842	46,866	43,392	14,161,911	17,025,663	31,187,574				-	-	-	#DIV/0!	#DIV/0!	#DIV/0!
	4176	4,584	8760	**1.035**	**1.035**	**1.035**	**48,727**	**47,829**	**48,257**	**196,618,713**	**211,929,809**	**408,548,522**				**-**	**-**	**-**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**
Jan	-4.3%	4.3%	0.0%	0.5%	0.5%	0.5%	118.1%	83.7%	99.6%	107.6%	90.6%	98.6%	[redacted]			-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Feb	0.0%	0.0%	0.0%	0.5%	0.5%	0.5%	109.1%	96.2%	102.3%	108.1%	95.3%	101.3%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Mar	4.8%	-3.9%	0.0%	0.5%	0.4%	0.5%	67.0%	108.2%	88.1%	74.2%	99.2%	87.2%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Apr	0.0%	0.0%	0.0%	0.4%	0.4%	0.4%	102.0%	57.4%	76.4%	101.2%	56.8%	75.7%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
May	-4.5%	4.1%	0.0%	0.5%	0.4%	0.4%	107.8%	65.8%	84.6%	97.4%	71.8%	83.8%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Jun	4.8%	-4.2%	0.0%	0.5%	0.4%	0.4%	75.8%	95.0%	85.6%	83.4%	86.0%	84.8%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Jul	0.0%	0.0%	0.0%	0.5%	0.4%	0.4%	101.3%	74.8%	87.1%	100.4%	74.0%	86.2%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Aug	0.0%	0.0%	0.0%	0.5%	0.4%	0.4%	94.7%	89.1%	91.7%	93.8%	88.3%	90.9%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Sep	0.0%	0.0%	0.0%	0.5%	0.4%	0.5%	85.3%	82.5%	83.8%	84.4%	81.7%	82.9%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Oct	-4.3%	4.3%	0.0%	0.5%	0.4%	0.4%	105.1%	59.4%	80.2%	95.2%	65.5%	79.4%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Nov	5.0%	-4.0%	0.0%	0.5%	0.4%	0.5%	81.5%	75.3%	78.3%	89.7%	67.6%	77.5%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
Dec	0.0%	0.0%	0.0%	0.5%	0.5%	0.5%	110.0%	94.1%	101.0%	108.9%	93.2%	100.0%				-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%
	0.0%	**0.0%**	**0.0%**	**0.5%**	**0.4%**	**0.5%**	**95.9%**	**81.0%**	**87.9%**	**95.0%**	**80.2%**	**87.0%**				**-100.0%**	**-100.0%**	**-100.0%**	**0.0%**	**0.0%**	**0.0%**

	Monthly Hours in 2025			HV FUEL COST ADJUSTMENT									KWh Requirement			Line Loss Factors			3PH FU
				Average Hourly KW Requirement			Sales			MC Revenue									Average Hourly KW Requirement
	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On
Scenario A (2024)																			
Jan	368	376	744	25,197	24,621	24,906	8,915,883	8,901,391	17,817,274	[redacted]			28,911,522	26,640,126	55,551,647	1.061	1.061	1.061	78,564
Feb	320	352	672	25,076	24,978	25,025	7,715,576	8,454,147	16,169,723				26,042,876	26,268,743	52,311,619	1.061	1.061	1.061	81,384
Mar	336	408	744	23,789	18,313	20,786	7,685,705	7,184,138	14,869,843				29,629,679	25,040,322	54,670,001	1.061	1.061	1.061	88,184
Apr	352	368	720	18,152	21,786	20,009	6,143,670	7,709,052	13,852,721				24,834,670	27,620,655	52,455,326	1.061	1.061	1.061	70,553
May	352	392	744	24,140	21,100	22,538	8,170,523	7,953,083	16,123,607				28,009,796	25,407,950	53,417,746	1.061	1.061	1.061	79,573
Jun	336	384	720	24,881	20,166	22,366	8,038,418	7,445,907	15,484,325				30,239,093	25,315,858	55,554,951	1.061	1.061	1.061	89,997
Jul	368	376	744	22,516	22,863	22,692	7,967,362	8,265,792	16,233,154				31,147,544	30,250,436	61,397,980	1.061	1.061	1.061	84,640
Aug	336	408	744	25,935	19,761	22,550	8,379,148	7,752,428	16,131,576				35,651,361	30,355,763	66,007,124	1.061	1.061	1.061	106,105
Sep	352	368	720	22,248	22,168	22,207	7,530,120	7,844,133	15,374,252				29,027,910	29,365,748	58,393,658	1.061	1.061	1.061	82,466
Oct	368	376	744	21,993	20,513	21,245	7,782,253	7,416,193	15,198,446				29,909,621	27,588,172	57,497,793	1.061	1.061	1.061	81,276
Nov	320	400	720	25,970	20,613	22,994	7,990,639	7,927,956	15,918,595				28,789,179	26,942,117	55,731,296	1.061	1.061	1.061	89,966
Dec	368	376	744	19,297	23,120	21,229	6,828,046	8,358,804	15,186,850				23,325,156	27,540,094	50,865,250	1.061	1.061	1.061	63,384
	4176	4584	8760	**23,198**	**21,602**	**22,362**	**93,147,343**	**95,213,023**	**188,360,366**				**345,518,408**	**328,335,984**	**673,854,392**	**1.061**	**1.061**	**1.061**	**82,739**
Scenario B:	**Monthly Hours in 2026**																		
	On	Off	Total																
Jan	352	392	744	-	-	-	-	-	-	[redacted]			29,156,817	26,610,879	55,767,696	1.052	1.052	1.052	82,832
Feb	320	352	672	-	-	-	-	-	-				26,585,311	26,020,489	52,605,800	1.052	1.052	1.052	83,079
Mar	352	392	744	-	-	-	-	-	-				26,519,356	28,347,838	54,867,193	1.052	1.052	1.052	75,339
Apr	352	368	720	-	-	-	-	-	-				28,051,965	23,892,171	51,944,135	1.052	1.052	1.052	79,693
May	336	408	744	-	-	-	-	-	-				27,521,832	22,574,938	50,096,769	1.052	1.052	1.052	81,910
Jun	352	368	720	-	-	-	-	-	-				24,574,733	24,040,460	48,615,193	1.052	1.052	1.052	69,815
Jul	368	376	744	-	-	-	-	-	-				28,477,718	25,413,628	53,891,346	1.052	1.052	1.052	77,385
Aug	336	408	744	-	-	-	-	-	-				30,964,620	28,783,121	59,747,741	1.052	1.052	1.052	92,157
Sep	352	368	720	-	-	-	-	-	-				27,741,370	28,342,518	56,083,888	1.052	1.052	1.052	78,811
Oct	352	392	744	-	-	-	-	-	-				29,620,017	24,773,377	54,393,394	1.052	1.052	1.052	84,148
Nov	336	384	720	-	-	-	-	-	-				27,306,815	25,845,587	53,152,401	1.052	1.052	1.052	81,270
Dec	368	376	744	-	-	-	-	-	-				23,926,224	26,649,892	50,576,116	1.052	1.052	1.052	65,017
	4176	4,584	8760	**-**	**-**	**-**	**-**	**-**	**-**				**330,446,776**	**311,294,898**	**641,741,674**	**1.052**	**1.052**	**1.052**	**79,130**
Jan	-4.3%	4.3%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	[redacted]			0.8%	-0.1%	0.4%	-0.9%	-0.9%	-0.9%	5.4%
Feb	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				2.1%	-0.9%	0.6%	-0.9%	-0.9%	-0.9%	2.1%
Mar	4.8%	-3.9%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-10.5%	13.2%	0.4%	-0.9%	-0.9%	-0.9%	-14.6%
Apr	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				13.0%	-13.5%	-1.0%	-0.9%	-0.9%	-0.9%	13.0%
May	-4.5%	4.1%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-1.7%	-11.2%	-6.2%	-0.9%	-0.9%	-0.9%	2.9%
Jun	4.8%	-4.2%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-18.7%	-5.0%	-12.5%	-0.9%	-0.9%	-0.9%	-22.4%
Jul	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-8.6%	-16.0%	-12.2%	-0.9%	-0.9%	-0.9%	-8.6%
Aug	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-13.1%	-5.2%	-9.5%	-0.9%	-0.9%	-0.9%	-13.1%
Sep	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-4.4%	-3.5%	-4.0%	-0.9%	-0.9%	-0.9%	-4.4%
Oct	-4.3%	4.3%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-1.0%	-10.2%	-5.4%	-0.9%	-0.9%	-0.9%	3.5%
Nov	5.0%	-4.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				-5.1%	-4.1%	-4.6%	-0.9%	-0.9%	-0.9%	-9.7%
Dec	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%				2.6%	-3.2%	-0.6%	-0.9%	-0.9%	-0.9%	2.6%
	0.0%	**0.0%**	**0.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**				**-4.4%**	**-5.2%**	**-4.8%**	**-0.9%**	**-0.9%**	**-0.9%**	**-4.4%**

EL COST ADJUSTMENT

	Monthly Hours in 2025					Sales			MC Revenue		
	On	Off	Total	Off	Total	On	Off	Total	On	Off	Total
Scenario A (2024)											
Jan	368	376	744	70,851	74,666	27,245,080	25,104,606	52,349,685			
Feb	320	352	672	74,627	77,845	24,541,781	24,754,629	49,296,410			
Mar	336	408	744	61,373	73,481	27,921,843	23,597,014	51,518,857			
Apr	352	368	720	75,056	72,855	23,403,216	26,028,618	49,431,833			
May	352	392	744	64,816	71,798	26,395,329	23,943,452	50,338,781			
Jun	336	384	720	65,927	77,160	28,496,131	23,856,667	52,352,798			
Jul	368	376	744	80,453	82,524	29,352,219	28,506,820	57,859,039			
Aug	336	408	744	74,401	88,719	33,596,439	28,606,076	62,202,515			
Sep	352	368	720	79,798	81,102	27,354,759	27,673,124	55,027,884			
Oct	368	376	744	73,373	77,282	28,185,649	25,998,007	54,183,656			
Nov	320	400	720	67,355	77,405	27,129,789	25,389,190	52,518,979			
Dec	368	376	744	73,245	68,367	21,980,709	25,952,700	47,933,409			
	4176	4584	8760	**71,627**	**76,924**	**325,602,942**	**309,410,903**	**635,013,845**			
Scenario B:	**Monthly Hours in 2026**										
	On	**Off**	**Total**								
Jan	352	392	744	67,885	74,957	27,719,805	25,299,346	53,019,151			
Feb	320	352	672	73,922	78,282	25,275,038	24,738,054	50,013,091			
Mar	352	392	744	72,316	73,746	25,212,333	26,950,698	52,163,031			
Apr	352	368	720	64,924	72,145	26,669,407	22,714,630	49,384,037			
May	336	408	744	55,331	67,334	26,165,401	21,462,318	47,627,720			
Jun	352	368	720	65,327	67,521	23,363,552	22,855,611	46,219,163			
Jul	368	376	744	67,589	72,435	27,074,176	24,161,102	51,235,278			
Aug	336	408	744	70,547	80,306	29,438,510	27,364,527	56,803,038			
Sep	352	368	720	77,018	77,894	26,374,120	26,945,640	53,319,760			
Oct	352	392	744	63,197	73,109	28,160,177	23,552,406	51,712,583			
Nov	336	384	720	67,306	73,823	25,960,982	24,571,771	50,532,753			
Dec	368	376	744	70,877	67,979	22,747,005	25,336,436	48,083,441			
	4176	4,584	8760	**67,909**	**73,258**	**314,160,506**	**295,952,540**	**610,113,046**			
Jan	-4.3%	4.3%	0.0%	-4.2%	0.4%	1.7%	0.8%	1.3%			
Feb	0.0%	0.0%	0.0%	-0.9%	0.6%	3.0%	-0.1%	1.5%			
Mar	4.8%	-3.9%	0.0%	17.8%	0.4%	-9.7%	14.2%	1.3%			
Apr	0.0%	0.0%	0.0%	-13.5%	-1.0%	14.0%	-12.7%	-0.1%			
May	-4.5%	4.1%	0.0%	-14.6%	-6.2%	-0.9%	-10.4%	-5.4%			
Jun	4.8%	-4.2%	0.0%	-0.9%	-12.5%	-18.0%	-4.2%	-11.7%			
Jul	0.0%	0.0%	0.0%	-16.0%	-12.2%	-7.8%	-15.2%	-11.4%			
Aug	0.0%	0.0%	0.0%	-5.2%	-9.5%	-12.4%	-4.3%	-8.7%			
Sep	0.0%	0.0%	0.0%	-3.5%	-4.0%	-3.6%	-2.6%	-3.1%			
Oct	-4.3%	4.3%	0.0%	-13.9%	-5.4%	-0.1%	-9.4%	-4.6%			
Nov	5.0%	-4.0%	0.0%	-0.1%	-4.6%	-4.3%	-3.2%	-3.8%			
Dec	0.0%	0.0%	0.0%	-3.2%	-0.6%	3.5%	-2.4%	0.3%			
	0.0%	**0.0%**	**0.0%**	**-5.2%**	**-4.8%**	**-3.5%**	**-4.3%**	**-3.9%**			

Case	2025 TEMPLATE COL 1	2026 TEMPLATE COL 2	% Variance
Avoided Cost_EHV	[redacted]		
MC_Rev_EHV			
Avoided Cost_HV			
MC_Rev_HV			
Avoided Cost_Distr			
MC_Rev_Distr			
MC_on			
MC_off			
MC_ave			
GR_on			
GR_off			
GR_ave			
TC_on			
TC_off			
AC_ave			
AC_on			
AC_off			
LF_ave			
MC_Jan			
MC_Feb			
MC_Mar			
MC_Apr			
MC_May			
MC_Jun			
MC_Jul			
MC_Aug			
MC_Sep			
MC_Oct			
MC_Nov			
MC_Dec			
MC_on_Jan			
MC_on_Feb			
MC_on_Mar			
MC_on_Apr			
MC_on_May			
MC_on_Jun			
MC_on_Jul			
MC_on_Aug			
MC_on_Sep			
MC_on_Oct			
MC_on_Nov			
MC_on_Dec			
MC_off_Jan			
MC_off_Feb			
MC_off_Mar			
MC_off_Apr			
MC_off_May			
MC_off_Jun			
MC_off_Jul			
MC_off_Aug			
MC_off_Sep			
MC_off_Oct			
MC_off_Nov			
MC_off_Dec			

Case	2023 GRA COS TEMPLATE COL 1	2026 GRA COS TEMPLATE COL 2	% Variance
Fixed Generation Costs			
OM&G	$135,308,637	$143,317,278	5.9%
Capital	$231,659,690	$194,421,766	-16.1%
ROE	$101,798,828	$89,089,776	-12.5%
	$468,767,155	$426,828,820	-8.9%
Fixed Transmission Costs			
OM&G	$28,078,384	$36,953,923	31.6%
Capital	$72,142,278	$68,109,579	-5.6%
ROE	$36,679,937	$34,131,358	-6.9%
	$136,900,598	$139,194,860	1.7%
EHV Portion	0.766	1.000	
Fixed Distribution Costs			
OM&G	$38,012,458	$72,219,496	90.0%
Capital	$144,921,581	$179,135,763	23.6%
ROE	$48,984,167	$65,700,296	34.1%
	$231,918,206	$317,055,555	36.7%
Total			
OM&G	$201,399,479	$252,490,698	25.4%
Capital	$448,723,549	$441,667,107	-1.6%
ROE	$187,462,932	$188,921,430	0.8%
	$837,585,960	$883,079,235	5.4%

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
3CP_GEN_EHV & HV	75.96	145.32	91.3%
3CP_GEN_HV	73.25		-100.0%
3CP_GEN_Distr	273.95	326.29	19.1%
3CP_GEN_NSR	6,815.27	6,888.54	1.1%
3CP_HV_HV	70.32		-100.0%
3CP_HV_Distr	262.99		-100.0%
3CP_HV_NSR	6,542.65		-100.0%
3CP_Distr_Distr	262.99	303.17	15.3%
3CP_HV_NSR	6,542.65	6,400.50	-2.2%
KWHs_EHV & HV_on	103,855,103	203,482,737	95.9%
KWHs_EHV & HV_off	121,129,585	219,246,501	81.0%
KWHs_HV_on	96,873,237		-100.0%
KWHs_HV_off	99,021,544		-100.0%
KWHs_Distr_on	345,518,408	330,446,776	-4.4%
KWHs_Distr_off	328,335,984	311,294,898	-5.2%
KWHs_Total_on			0.0%
KWHs_Total_off			0.0%
KWHs_Total			0.0%
Customers_EHV and HV	2	8	300.0%
Customers_HV	6		-100.0%
Customers_Distr	39	39	0.0%
Customers_All	558,998	566,431	1.3%
KWHs_Total_req	10,678,536,933	10,778,679,762	0.9%
RTP_req_off_Jan	[redacted]		
RTP_req_off_Feb			
RTP_req_off_Mar			
RTP_req_off_Apr			
RTP_req_off_May			
RTP_req_off_Jun			
RTP_req_off_Jul			
RTP_req_off_Aug			
RTP_req_off_Sep			
RTP_req_off_Oct			
RTP_req_off_Nov			
RTP_req_off_Dec			
RTP_req_on_Jan			
RTP_req_on_Feb			
RTP_req_on_Mar			
RTP_req_on_Apr			
RTP_req_on_May			
RTP_req_on_Jun			
RTP_req_on_Jul			
RTP_req_on_Aug			
RTP_req_on_Sep			
RTP_req_on_Oct			
RTP_req_on_Nov			
RTP_req_on_Dec			

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
RTP_sales_off_Jan	[redacted]		
RTP_sales_off_Feb			
RTP_sales_off_Mar			
RTP_sales_off_Apr			
RTP_sales_off_May			
RTP_sales_off_Jun			
RTP_sales_off_Jul			
RTP_sales_off_Aug			
RTP_sales_off_Sep			
RTP_sales_off_Oct			
RTP_sales_off_Nov			
RTP_sales_off_Dec			
RTP_sales_on_Jan			
RTP_sales_on_Feb			
RTP_sales_on_Mar			
RTP_sales_on_Apr			
RTP_sales_on_May			
RTP_sales_on_Jun			
RTP_sales_on_Jul			
RTP_sales_on_Aug			
RTP_sales_on_Sep			
RTP_sales_on_Oct			
RTP_sales_on_Nov			
RTP_sales_on_Dec			
3PH_Elig_req_off_Jan	26,640,126	26,610,879	-0.1%
3PH_Elig_req_off_Feb	26,268,743	26,020,489	-0.9%
3PH_Elig_req_off_Mar	25,040,322	28,347,838	13.2%
3PH_Elig_req_off_Apr	27,620,655	23,892,171	-13.5%
3PH_Elig_req_off_May	25,407,950	22,574,938	-11.2%
3PH_Elig_req_off_Jun	25,315,858	24,040,460	-5.0%
3PH_Elig_req_off_Jul	30,250,436	25,413,628	-16.0%
3PH_Elig_req_off_Aug	30,355,763	28,783,121	-5.2%
3PH_Elig_req_off_Sep	29,365,748	28,342,518	-3.5%
3PH_Elig_req_off_Oct	27,588,172	24,773,377	-10.2%
3PH_Elig_req_off_Nov	26,942,117	25,845,587	-4.1%
3PH_Elig_req_off_Dec	27,540,094	26,649,892	-3.2%
3PH_Elig_req_on_Jan	28,911,522	29,156,817	0.8%
3PH_Elig_req_on_Feb	26,042,876	26,585,311	2.1%
3PH_Elig_req_on_Mar	29,629,679	26,519,356	-10.5%
3PH_Elig_req_on_Apr	24,834,670	28,051,965	13.0%
3PH_Elig_req_on_May	28,009,796	27,521,832	-1.7%
3PH_Elig_req_on_Jun	30,239,093	24,574,733	-18.7%
3PH_Elig_req_on_Jul	31,147,544	28,477,718	-8.6%
3PH_Elig_req_on_Aug	35,651,361	30,964,620	-13.1%
3PH_Elig_req_on_Sep	29,027,910	27,741,370	-4.4%
3PH_Elig_req_on_Oct	29,909,621	29,620,017	-1.0%
3PH_Elig_req_on_Nov	28,789,179	27,306,815	-5.1%
3PH_Elig_req_on_Dec	23,325,156	23,926,224	2.6%

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
3PH_Elig_sales_off_Jan	25,104,606	25,299,346	0.8%
3PH_Elig_sales_off_Feb	24,754,629	24,738,054	-0.1%
3PH_Elig_sales_off_Mar	23,597,014	26,950,698	14.2%
3PH_Elig_sales_off_Apr	26,028,618	22,714,630	-12.7%
3PH_Elig_sales_off_May	23,943,452	21,462,318	-10.4%
3PH_Elig_sales_off_Jun	23,856,667	22,855,611	-4.2%
3PH_Elig_sales_off_Jul	28,506,820	24,161,102	-15.2%
3PH_Elig_sales_off_Aug	28,606,076	27,364,527	-4.3%
3PH_Elig_sales_off_Sep	27,673,124	26,945,640	-2.6%
3PH_Elig_sales_off_Oct	25,998,007	23,552,406	-9.4%
3PH_Elig_sales_off_Nov	25,389,190	24,571,771	-3.2%
3PH_Elig_sales_off_Dec	25,952,700	25,336,436	-2.4%
3PH_Elig_sales_on_Jan	27,245,080	27,719,805	1.7%
3PH_Elig_sales_on_Feb	24,541,781	25,275,038	3.0%
3PH_Elig_sales_on_Mar	27,921,843	25,212,333	-9.7%
3PH_Elig_sales_on_Apr	23,403,216	26,669,407	14.0%
3PH_Elig_sales_on_May	26,395,329	26,165,401	-0.9%
3PH_Elig_sales_on_Jun	28,496,131	23,363,552	-18.0%
3PH_Elig_sales_on_Jul	29,352,219	27,074,176	-7.8%
3PH_Elig_sales_on_Aug	33,596,439	29,438,510	-12.4%
3PH_Elig_sales_on_Sep	27,354,759	26,374,120	-3.6%
3PH_Elig_sales_on_Oct	28,185,649	28,160,177	-0.1%
3PH_Elig_sales_on_Nov	27,129,789	25,960,982	-4.3%
3PH_Elig_sales_on_Dec	21,980,709	22,747,005	3.5%
HV_Elig_req_off_Jan	9,257,446		-100.0%
HV_Elig_req_off_Feb	8,792,313		-100.0%
HV_Elig_req_off_Mar	7,471,503		-100.0%
HV_Elig_req_off_Apr	8,017,414		-100.0%
HV_Elig_req_off_May	8,271,207		-100.0%
HV_Elig_req_off_Jun	7,743,743		-100.0%
HV_Elig_req_off_Jul	8,596,423		-100.0%
HV_Elig_req_off_Aug	8,062,525		-100.0%
HV_Elig_req_off_Sep	8,157,898		-100.0%
HV_Elig_req_off_Oct	7,712,840		-100.0%
HV_Elig_req_off_Nov	8,245,074		-100.0%
HV_Elig_req_off_Dec	8,693,156		-100.0%
HV_Elig_req_on_Jan	9,272,519		-100.0%
HV_Elig_req_on_Feb	8,024,199		-100.0%
HV_Elig_req_on_Mar	7,993,133		-100.0%
HV_Elig_req_on_Apr	6,389,416		-100.0%
HV_Elig_req_on_May	8,497,344		-100.0%
HV_Elig_req_on_Jun	8,359,955		-100.0%
HV_Elig_req_on_Jul	8,286,056		-100.0%
HV_Elig_req_on_Aug	8,714,314		-100.0%
HV_Elig_req_on_Sep	7,831,324		-100.0%
HV_Elig_req_on_Oct	8,093,543		-100.0%
HV_Elig_req_on_Nov	8,310,264		-100.0%
HV_Elig_req_on_Dec	7,101,168		-100.0%
HV_Elig_sales_off_Jan	8,901,391		-100.0%

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
HV_Elig_sales_off_Feb	8,454,147		-100.0%
HV_Elig_sales_off_Mar	7,184,138		-100.0%
HV_Elig_sales_off_Apr	7,709,052		-100.0%
HV_Elig_sales_off_May	7,953,083		-100.0%
HV_Elig_sales_off_Jun	7,445,907		-100.0%
HV_Elig_sales_off_Jul	8,265,792		-100.0%
HV_Elig_sales_off_Aug	7,752,428		-100.0%
HV_Elig_sales_off_Sep	7,844,133		-100.0%
HV_Elig_sales_off_Oct	7,416,193		-100.0%
HV_Elig_sales_off_Nov	7,927,956		-100.0%
HV_Elig_sales_off_Dec	8,358,804		-100.0%
HV_Elig_sales_on_Jan	8,915,883		-100.0%
HV_Elig_sales_on_Feb	7,715,576		-100.0%
HV_Elig_sales_on_Mar	7,685,705		-100.0%
HV_Elig_sales_on_Apr	6,143,670		-100.0%
HV_Elig_sales_on_May	8,170,523		-100.0%
HV_Elig_sales_on_Jun	8,038,418		-100.0%
HV_Elig_sales_on_Jul	7,967,362		-100.0%
HV_Elig_sales_on_Aug	8,379,148		-100.0%
HV_Elig_sales_on_Sep	7,530,120		-100.0%
HV_Elig_sales_on_Oct	7,782,253		-100.0%
HV_Elig_sales_on_Nov	7,990,639		-100.0%
HV_Elig_sales_on_Dec	6,828,046		-100.0%
EHV & HV_Elig_req_off_Jan	10,071,824	19,288,323	91.51%
EHV & HV_Elig_req_off_Feb	8,961,947	17,585,124	96.22%
EHV & HV_Elig_req_off_Mar	9,375,993	18,759,554	100.08%
EHV & HV_Elig_req_off_Apr	10,763,165	16,945,276	57.44%
EHV & HV_Elig_req_off_May	10,519,019	18,153,433	72.58%
EHV & HV_Elig_req_off_Jun	10,108,151	18,885,069	86.83%
EHV & HV_Elig_req_off_Jul	10,697,383	18,697,161	74.78%
EHV & HV_Elig_req_off_Aug	10,339,095	19,547,752	89.07%
EHV & HV_Elig_req_off_Sep	10,173,085	18,561,560	82.46%
EHV & HV_Elig_req_off_Oct	10,335,084	17,179,850	66.23%
EHV & HV_Elig_req_off_Nov	10,707,724	18,021,750	68.31%
EHV & HV_Elig_req_off_Dec	9,077,115	17,621,650	94.1%
EHV & HV_Elig_req_on_Jan	8,983,384	18,743,940	108.7%
EHV & HV_Elig_req_on_Feb	7,877,137	16,474,532	109.1%
EHV & HV_Elig_req_on_Mar	8,621,681	15,086,706	75.0%
EHV & HV_Elig_req_on_Apr	7,952,051	16,066,756	102.0%
EHV & HV_Elig_req_on_May	9,182,422	18,211,397	98.3%
EHV & HV_Elig_req_on_Jun	8,928,497	16,447,406	84.2%
EHV & HV_Elig_req_on_Jul	9,222,025	18,563,631	101.3%
EHV & HV_Elig_req_on_Aug	9,462,353	18,419,759	94.7%
EHV & HV_Elig_req_on_Sep	8,935,693	16,555,833	85.3%
EHV & HV_Elig_req_on_Oct	9,047,178	17,745,175	96.1%
EHV & HV_Elig_req_on_Nov	8,659,558	16,505,809	90.6%
EHV & HV_Elig_req_on_Dec	6,983,123	14,661,793	110.0%

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
EHV & HV_Elig_sales_off_Jan	9,778,470	18,639,373	90.6%
EHV & HV_Elig_sales_off_Feb	8,700,919	16,991,841	95.3%
EHV & HV_Elig_sales_off_Mar	9,102,906	18,133,888	99.2%
EHV & HV_Elig_sales_off_Apr	10,449,675	16,386,254	56.8%
EHV & HV_Elig_sales_off_May	10,212,640	17,550,342	71.8%
EHV & HV_Elig_sales_off_Jun	9,813,739	18,256,913	86.0%
EHV & HV_Elig_sales_off_Jul	10,385,808	18,075,252	74.0%
EHV & HV_Elig_sales_off_Aug	10,037,956	18,898,792	88.3%
EHV & HV_Elig_sales_off_Sep	9,876,782	17,942,161	81.7%
EHV & HV_Elig_sales_off_Oct	10,034,062	16,609,383	65.5%
EHV & HV_Elig_sales_off_Nov	10,395,848	17,419,947	67.6%
EHV & HV_Elig_sales_off_Dec	8,812,733	17,025,663	93.2%
EHV & HV_Elig_sales_on_Jan	8,721,732	18,107,019	107.6%
EHV & HV_Elig_sales_on_Feb	7,647,706	15,914,162	108.1%
EHV & HV_Elig_sales_on_Mar	8,370,564	14,577,683	74.2%
EHV & HV_Elig_sales_on_Apr	7,720,438	15,529,837	101.2%
EHV & HV_Elig_sales_on_May	8,914,973	17,598,749	97.4%
EHV & HV_Elig_sales_on_Jun	8,668,444	15,893,599	83.4%
EHV & HV_Elig_sales_on_Jul	8,953,423	17,940,188	100.4%
EHV & HV_Elig_sales_on_Aug	9,186,751	17,801,249	93.8%
EHV & HV_Elig_sales_on_Sep	8,675,430	15,998,506	84.4%
EHV & HV_Elig_sales_on_Oct	8,783,668	17,147,547	95.2%
EHV & HV_Elig_sales_on_Nov	8,407,338	15,948,264	89.7%
EHV & HV_Elig_sales_on_Dec	6,779,731	14,161,911	108.9%

2026 Annually Adjusted Rates
Method Used to Calculate 1P-RTP Tariffs

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Background:

One Part Real Time Pricing (1P-RTP) Tariffs is a Time of Use rate designed to encourage the customer to Shift their Load from Higher On-peak rate to Lower-Off peak rates. A higher price would signal customers to avoid usage during high peaking hours and increase usage at lower off-peak hours and NSPI may be able to avoid higher costs to the benefit of all customers because of improved utility's load factor.

The rates allow customers to buy energy at a price that varies hourly. That price is the sum of two components: namely, the marginal cost of producing the energy in that hour, plus a fixed cost adder which comprise embedded fixed cost adders and customer cost adder.

NSPI's cost of producing energy varies every hour. As the electricity demand increases during peak hours, a utility will start bringing generating units online with more expensive energy costs, which include fuel and variable Operation and Maintenance (O&M) costs. Conversely, when electric demand or load decreases, the utility will start shutting down the generating units with higher energy costs.

Rate Design:

The two[1] rates allow customers to buy energy at a price that varies on an hourly basis. That price is the sum of the marginal cost of producing the energy in that hour, plus a fixed cost adder. These adders are submitted to the Board for approval annually and is based on budgeted costs for the next year.

Customers on any of the two rates pay adders varying to reflect the fixed costs to serve customers at the two different voltage levels.

The rate consists of an energy charge only. There is no demand charge.

Generation fixed costs are recovered during the on-peak hours only, while transmission and distribution and customer costs are recovered during all the hours.

Method Used to Calculate 1P-RTP Tariffs:

The Fixed Cost Adders

The fixed cost rate components are designed to recover fully embedded fixed Generation cost of services.

[1] Currently there are three One Part RTP Tariffs in effect: (a) two transmission-based tariffs: 1P-RTP Extra High Voltage (EHV) and 1P-RTP High Voltage (HV), and (b) one distribution-based tariff: 1P-RTP Distribution Voltage. This change stems from the consensus Cost of Service Study (COSS), filed in the 2026-2027 GRA (M12451) which no longer provides a breakdown of transmission costs by the EHV and HV components

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NS Power utilizes the Partially Confidential electronic Excel file, Appendix B2, to calculate the 1P-RTP rates by using the following method.

- The costing determinants such as Monthly Energy requirement, Monthly sales customer counts and Coincident Peaks for January February and December 2024 (3CPs) are inputted into "CostDetInput" tab of the Appendix.

- The NS power's embedded Fixed Generation, Transmission and Distribution that comes from the proposed 2026 Cost of Service Study (COSS) that was provided in the Company's 2026-2027 General Rate Application[2] (GRA) are entered into the "FixedCostInput". The Fixed cost in exhibit 6.1 of the 2026 COSS are broken down by Type of expense and customer service level in the Appendix B2 file.

- Consistent with its October 15, 2025, memorandum to AAR Stakeholders (Appendix J) on NS Power's Proposal for Methodological Changes to 1P-RTP Tariff, the Company no longer calculates the fuel cost adjustment in the Adders.

- The "Report" tab calculates the riders. The fixed embedded cost, customer cost to the service level by using the 3 coincident peaks and relative share of off and peak sales are divided by the service level sales.

Cost of Service Fixed Cost Riders

(a) Generation Cost Fixed Cost.

(i) The generation total cost of $426.9 million broken down into expense type (operating, capital, and Return) in the 2026 Cost of service is apportioned to Transmission, Distribution service level and non eligible customers using the relative share of their 2026's 3 coincident peaks (CP's).

(ii) The generation costs in each service level are then segregated by On and off peak by using the relative share On and off-peak sales. All the generation cost occurs during the On-Peak period only.

(iii) The Generation fixed cost rates components by service level are derived by dividing the generation cost by the Service level on peak sales in kWh. Appendix B submitted with the evidence provides in detail the riders by expense type. Please refer to the table below that shows the simplified calculations.

[2] M12451 – NS Power, 2026-2027 General Rate Application. September 17, 2025.

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				A/C	B/C			G/G11	H*I	I	J-I	J/A	K/B
	Costing Determinants									Categorized amount in Millions		Adders in $ / kWh	
Customer Class	Sales			On	Off		3 CPS		Amount in Millions			On	Off
	On Peak	Off Peak	Total	On Peak	Off Peak	Line Losses		Relative % Share	Apportion to Service Level	On Peak	Off Peak	On Peak	Off Peak
1 Transmission	196,618,713	211,929,809	408,548,522	48%	52%	0%	145.32	2.11%	$9,004	$9,004	$0	$0.04580	$0.00000
3 Distribution	314,160,506	295,952,540	610,113,046	51%	49%	0%	326.29	4.74%	$20,218	$20,218	$0	$0.06435	$0.00000
4 Non Eligible (Customers not eligible for the rate)							6,416.93	93.15%	$397,607	$397,607	$0		
5 Total							**6,888.54**	**100.00%**	**$426,829**				

(b) Transmission Cost Fixed Cost.

(i) The Transmission total cost of $139.2 Million broken down by expense type; operating, capital and Return in the 2026 Cost of service also in Appendix D provided with the application is apportion to Transmission, Distribution service level and non eligible customers by using the 2026 relative share of their 3CPS

(ii) The transmission costs in each service level are then segregated by On and off peak by using the relative share of On and Off-peak sales.

(iii) The Transmission fixed cost rate components by service level are derived by dividing the cost by the Service level per period and by On and Off sales in kWh. Please refer to calculation below. Appendix B calculations provide in detail the riders by expense type. Please refer to table below that show the simplified calculations.

1

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				A/C	B/C			G/G11	H*I	I	J-I	J/A	K/B
	Costing Determinants									Categorized amount in Millions		Adders in $ / kWh	
Customer Class	Sales			On	Off		3 CPS		Amount in Millions			On	Off
	On Peak	Off Peak	Total	On Peak	Off Peak		0%	Relative % Share	Apportion to Service Level	On Peak	Off Peak	On Peak	Off Peak
Transmission	196,618,713	211,929,809	408,548,522	48%	52%		145.32	2.11%	$2,936.5	$1,413.212	$1,523.262	$0.007188	$0.007188
Distribution	314,160,506	295,952,540	610,113,046	51%	49%		326.29	4.74%	$6,593.3	$3,395.031	$3,198.264	$0.010807	$0.010807
Non Eligible (Customers not eligible for the rate)							6,416.93	93.15%	$129,665				
Total							**6,888.54**	**100.00%**	**$139,195**				

(c) Distribution Cost Fixed Cost

(i) The Distribution total cost of $317.1 Million broken down broken down by expense type; Operating, Capital and Return in 2026 Cost of service is apportioned to Distribution service level and non eligible customers only by using the 2026 Relative share of their 3CPS adjusted by the line losses of 7.1% to reflect the usage at distribution level.

(ii) The Distribution cost amounts by service voltage level are then segregated by the relative into On and off-peak category by using the relative share of time of use sales.

(iii) The Distribution cost fixed cost rates in distribution voltage level are derived by dividing the cost at distribution by On and Off sales in kWh. Please refer to calculation below. Appendix B calculations provide in detail the riders by expense type. Please refer to table below that show the simplified calculations.

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				**A/C**	**B/C**			**G/G11**	**H*I**	**I**	**J-I**	**J/A**	**K/B**
	Costing Determinants									**Categorized amount in Millions**		**Adders in $ / kWh**	
Customer Class	**Sales**			**On**	**Off**		**3 CPS**		**Amount in**			**On**	**Off**
	On Peak	**Off Peak**	**Total**	**On Peak**	**Off Peak**	**Line Loss**	**4%**	**Relative % Share**	**Millions Apportion to Service Level**	**On Peak**	**Off Peak**	**On Peak**	**Off Peak**
Transmission	196,618,713	211,929,809	408,548,522	48%	52%							-	-
Distribution	314,160,506	295,952,540	610,113,046	51%	49%	7%	303.17	4.74%	$15,018	$7,733	$7,285	0.024615	0.024615
Non Eligible (Customers not elligible for the rate)							6,097.33	95.26%	$302,037				
Total						0%	6,400.50	**100.00%**	**$317,056**				
Notes													
The 3 CPs Usage at distribution is reduced by the Line losses of 7.1%													

(d) Customer Cost

(i) The Average Cost per month per customer in each service level is $400.

(ii) The customer cost is then multiplied by 12 Months to arrive at the yearly amount.

(iii) The yearly customer cost in each service voltage level is then segregated by On and Off-peak cost by using the relative share of On and off sales.

(iv) The customer cost adders by service level are derived by dividing the customer cost at the Service level per period and On and Off sales in kWh. Please refer to table below that show the simplified calculations.

Fuel Cost Adjustment

There is no longer avoided fuel cost adjustment from the difference between these values result to partially offset the fixed cost. Refer to Section 4.1 of 2026 AAR Application for the rationale behind removal of Avoided Fuel Cost Adjustment.

2026 Annually Adjusted Rates
Method Used to Calculate 1P-RTP Tariffs

NON-CONFIDENTIAL

Adding the Generation, Transmission, distribution, customer costs and fuel cost adjustment rates by Service level in the tables above produces the 2026 1P-RTP components as shown below that reconcile to those in Figure 3 included in NS power's evidence.

2026 On peak rates in Cents/ kWh								Fig 3 rates in Cents/ kWh			Variance		
Fixed Cost Adder						Fuel ADJ	Grand Total						
	Generation	Transmission	Distribution	Customer Cost	**Total**	Total		Adders	Fuel Adjustment	Total	Adders	Fuel Adj.	Total
Transmission	4.580	0.7188	0.000	0.0094	**5.308**	0.000	5.308	5.3078	0.000	5.308	0.000	0.00	0.00
Distribution	6.435	1.081	2.462	0.0306	**10.008**	0.000	10.008	10.008	0.000	10.008	0.00	0.00	0.00

2026 Off Peak Rates in Cents/ Kwh													
Fixed Cost Adder						Fuel ADJ	Grand Total	Adders	Fuel Adju	Total	Adders	Fuel Adj.	Total
	Generation	Transmission	Distribution	Customer Cost	**Total**	Total							
Transmission	0.000	0.719	0.000	0.0094	**0.728**	0.000	0.728	0.728	0.000	0.728	0.00	0.00	0.00
Distribution	0.000	1.081	2.462	0.0306	**3.573**	0.000	3.573	3.573	0.000	3.573	0.00	0.00	0.00

2026 On peak rates in Cents/ kWh								Fig 4 rates in Cents/ kWh			Variance		
	Fixed Cost Adder					Fuel ADJ	Grand Total						
	Generation	Transmission	Distribution	Customer Cost	**Total**	Total		Adders	Fuel Adjustment	Total	Adders	Fuel Adj.	Total
Transmission	4.580	0.7188	0.000	0.0094	**5.308**	0.000	5.308	5.3078	0.000	5.308	0.000	0.00	0.00
Distribution	6.435	1.081	2.462	0.0306	**10.008**	0.000	10.008	10.008	0.000	10.008	0.00	0.00	0.00

2026 Off Peak Rates in Cents/ Kwh													
	Fixed Cost Adder					Fuel ADJ	Grand Total	Adders	Fuel Adju	Total	Adders	Fuel Adj.	Total
	Generation	Transmission	Distribution	Customer Cost	**Total**	Total							
Transmission	0.000	0.719	0.000	0.0094	**0.728**	0.000	0.728	0.728	0.000	0.728	0.00	0.00	0.00
Distribution	0.000	1.081	2.462	0.0306	**3.573**	0.000	3.573	3.573	0.000	3.573	0.00	0.00	0.00

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				A/C	B/C			G/G11	H*I	I	J-I	J/A	K/B
	Costing Determinants									Categorized amount in Millions		Adders in $ / kWh	
Customer Class	Sales			On	Off		3 CPS		Amount in Millions			On	Off
	On Peak	Off Peak	Total	On Peak	Off Peak	Line Losses		Relative % Share	Apportion to Service Level	On Peak	Off Peak	On Peak	Off Peak
Transmission	196,618,713	211,929,809	408,548,522	48%	52%	0%	145.32	2.11%	$9,004	$9,004	$0	$0.04580	$0.00000
Distribution	314,160,506	295,952,540	610,113,046	51%	49%	0%	326.29	4.74%	$20,218	$20,218	$0	$0.06435	$0.00000
Non Eligible (Customers not eligible for the rate)							6,416.93	93.15%	$397,607	$397,607	$0		
Total							**6,888.54**	**100.00%**	**$426,829**				

1

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				A/C	B/C			G/G11	H*I	I	J-I	J/A	K/B
	Costing Determinants								Amount in Millions	Categorized amount in Millions		Adders in $ / kWh	
Customer Class	Sales			On	Off	3 CPS			Apportion to Service Level			On	Off
	On Peak	Off Peak	Total	On Peak	Off Peak		0%	Relative % Share		On Peak	Off Peak	On Peak	Off Peak
Transmission	196,618,713	211,929,809	408,548,522	48%	52%		145.32	2.11%	$2,936.474	$1,413.212	$1,523.262	$0.007188	$0.007188
Distribution	314,160,506	295,952,540	610,113,046	51%	49%		326.29	4.74%	$6,593.295	$3,395.031	$3,198.264	$0.010807	$0.010807
Non Eligible (Customers not eligible for the rate)							6,416.93	93.15%	$129,665				
Total							**6,888.54**	**100.00%**	**$139,195**				

	A	B	C	D	E	F	G	H	I	J	K	L	M
Formular				A/C	B/C			G/G11	H*I	I	J-I	J/A	K/B
	Costing Determinants									Categorized amount in Millions		Adders in $ / kWh	
Customer Class	Sales			On	Off		3 CPS		Amount in Millions			On	Off
	On Peak	Off Peak	Total	On Peak	Off Peak	Line Loss	4%	Relative % Share	Apportion to Service Level	On Peak	Off Peak	On Peak	Off Peak
Transmission	196,618,713	211,929,809	408,548,522	48%	52%							-	-
Distribution	314,160,506	295,952,540	610,113,046	51%	49%	7%	303.17	4.74%	$15,018	$7,733	$7,285	0.024615	0.024615
Non Eligible (Customers not elligible for the rate)							6,097.33	95.26%	$302,037				
Total						0%	6,400.50	**100.00%**	**$317,056**				

Notes

The 3 CPs Usage at distribution is reduced by the Line losses of 7.1%

	A	B	C	D	E	F	G	H	I	J	K	L
Formular				A/C	B/C				D*H	E*H	I/A*100	I/A*100
	Costing Determinants							F*G*12	Off	On	Adders Cents/ kWh	
Customer Class	Sales					Average Customer count	Average Cost per month	Cost per Year	On Peak	Off Peak	On Peak	Off Peak
	On Peak	Off Peak	Total	On Peak	Off Peak							
Transmission	196,618,713	211,929,809	408,548,522	48%	52%	8	$400	$38,400	$18,480	$19,920	0.0094	0.0094
Distribution	314,160,506	295,952,540	610,113,046	51%	49%	39	$400	$186,767	$96,170	$90,597	0.0306	0.0306

Appendix 6.1 of 2024 COSS	Total Generation		$426,828,820
	Total Transmission		$139,194,860
	Distribution		$317,055,555
	Total Fixed Cost		**$883,079,235**
	Transmission	100.00%	$139,194,860
Allocation	Transmission	Generation Portion	48.3%
		Transmission	51.7%
	Distribution	Generation Portion	48.3%
		Transmission	51.7%

	Transmission			DISTRIBUTION		
	ON	**OFF**	**Total**	**ON**	**OFF**	**Total**
Sales	196,618,713	211,929,809	408,548,522	314,160,506	295,952,540	610,113,046
% of On and Off Peak sa	48.13%	51.87%	100.00%	51.49%	48.51%	100.00%
Avoided Cost			$0		$0	
Revenue			$0		$0	
Fuel Adjustment			$0		$0	
Generation Portion	$0		$0	$0		$0
Transmission	$0	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0	$0
Generation Portion	$0.00000	$0.00000		$0.00000	$0.00000	
Transmission	$0.00000	$0.00000		$0.00000	$0.00000	
Fuel Cost Adj. rate	$0.00000	$0.00000		$0.00000	$0.00000	

AVAILABILITY

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate;
(ii.) Extra Large Industrial Active Demand Control Tariff and PHP Tariff;
(iii.) Shore Power Tariff; and
(iv.) Interruptible Rider to the Large Industrial Rate.

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

ENERGY CHARGE

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

Base Energy Charge Components	**Transmission Voltage of 69 kV or Higher (cents per kWh)**	**Distribution Voltage (cents per kWh)**
Fuel Cost	6.900	7.062
Fixed Cost Adder	2.516	4.064
Total	9.417	**11.126**

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

SUPPLY INTERRUPTIONS

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non- compliance took place.

Penalty for Non-Compliance

All energy served after the 10-minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2,000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

SPECIAL CONDITIONS

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and

metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection, and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two-year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design

and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

SHORE POWER CALCULATION						
	2026					
	MWh Requirement				Unit Revenue	
	Total at Generator's Gate[(1)]	By Voltage Class	Total non-demand related fixed cost (thousands)	Unit Production Cost at Generator's Gate	**Transmission**	**Distr**
Line Losses					2.43%	4.83%
Unit Fuel Cost (Cents/kWh)				**6.736**	**6.900**	**7.062**
Non-Demand-related						
Generation	11,406,662		$238,981.77	2.095	2.146	2.196
Transmission	11,406,662	422,729	$0.00	-	-	-
Distribution	10,983,933	683,216	$155,990.48	1.420		1.489
Distribution Other than 3 Ph	10,300,717	10,300,717				
Retail	11,406,662	11,406,662	$41,238.83	0.362	0.370	0.379
Unit Fixed Cost (Cents/kWh)			**$436,211.09**	**3.877**	**2.516**	**4.064**
Rate (Cents/kWh)					**9.417**	**11.126**
Footnotes						

(1) Please refer to tab "Usage Statistics" of Appendix D. The total Energy Requirement is made up of ATL rate classes and ELIADC whose load was included above-the-line under the PHP class in the 2026 GRA COSS.

COST BREADOWN BY FUNCTIONAL AREA

Source: 2026 COSS with GRA application Filing

RATE CLASS DISAGGREGATION ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2026

CLASS : TOTAL COMPANY

	RATE BASE	COSTS (Source Exh 6)									
		Variable	Fixed						Unit Cost		
		Fuel	Operating	Capital	Return	Total	Total Cost	Units Sold	Demand	Energy	Customer
Generation											
Usage (Energy)	$1,537,126	$741,931	$75,193	$109,836	$53,952	$238,982	$980,913	10,548,590	---	9.299	---
Reliability (Demand)	$1,001,086	$169,774	$68,124	$84,585	$35,138	$187,847	357,621	22,327,201	$16.017	---	---
Total Generation	$2,538,213	$911,705	$143,317	$194,422	$89,090	$426,829	$1,338,534		$16.017	9.299	$0.000
MWh Sales		10,548,590	10,548,590	10,548,590	10,548,590	10,548,590	10,548,590				
MWh Energy Requirement		11,303,785									
kW 3 CP		9,225,751									
kW 12 NCP		22,327,201									
Unit Cost (cents/kW.h)		8.643	1.359	1.843	0.845	4.046	12.689				
Transmission/Distribution											
Delivery--Trans.(Eng) - HV	0	0	$0	$0	$0	0	$0	10,548,590	---	0.000	---
Delivery--Trans.(Eng) - EHV	0	0	0	0	0	0	0	10,548,590		0.000	
Delivery--Trans.(Dmd) - HV	0	0	0	0	0	0	0	22,327,201	$0.000	---	---
Delivery--Trans.(Dmd) - EHV	972,420	0	36,954	68,110	34,131	139,195	139,195	22,327,201	$6.234	---	---
Total Transmission	$972,420	$0	$36,954	$68,110	$34,131	$139,195	$139,195		$6.234	-	$0.000
Delivery -- Dist. (Demand)	1,059,509	0	19,085	104,792	37,188	161,065	161,065	22,327,201	$7.214	---	---
Delivery -- Dist. (Customer)	812,326	0	53,134	74,344	28,512	155,990	155,990	6,478,160	---	---	$24.079
Total Distribution	1,871,835	0	72,219	179,136	65,700	317,056	317,056		$7.214	-	$24.079
Total Transmission/Distribution	$2,844,254	$0	$109,173	$247,245	$99,832	$456,250	$456,250		$13.448	-	$24.079
kW.h Sold		---	10,548,590	10,548,590	10,548,590	10,548,590	10,548,590				
Unit Cost (cents/kW.h)		---	1.035	2.344	0.946	4.325	4.325				
Retail											
Customer -- Field		0	$6,498	0	0	$6,498	$6,498	6,478,160	0.000	0.000	$1.003
Customer -- Head Office	206,870	0	2,547	11,437	7,261	21,246	21,246	6,478,160	0.000	0.000	$3.280
Total Customer	$206,870	0	9,045	11,437	7,261	27,744	27,744	6,478,160	$0.000	-	$4.283
Marketing		0	13,495	0	0	13,495	13,495	6,478,160	0.000	0.000	$2.083
Total Retail	$206,870	$0	$22,540	$11,437	$7,261	$41,239	41,239	6,478,160	0	-	$6.366
Total Customers x 12 months		---	6,478,160			6,054,372	6,054,372				
Unit Cost ($/month)		---	$3.479			$3.479	$3.479				
TOTAL	**$5,589,337**	**$911,705**	**$275,031**	**$453,105**	**$196,183**	**$924,318**	**$1,836,023**		$29.465	9.299	$30.445
Unit Cost (cents/kW.h)		**8.643**	**2.607**	**4.295**	**1.860**	**8.762**	**17.405**				

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2026

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) 3CP MW	(11) 3CP Contribution
(1) DOMESTIC	5,286,337,241	8.2%	5,721,931,430	1,461,049	90.4%	1,321,016	13.9%	1,504,675	43.41%	4,365	66.4%
(2) SMALL GENERAL	376,992,742	8.2%	407,868,448	82,774	84.9%	70,275	12.2%	78,842	59.06%	229	3.5%
(3) GENERAL	2,308,034,614	**7.9%**	2,490,138,545	431,533	**94.1%**	406,073	**11.0%**	450,556	**63.09%**	1,236	18.8%
(4) GENERAL LARGE	363,766,784	5.1%	382,282,513	60,859	73.6%	44,792	6.7%	47,805	91.29%	140	2.1%
(5) SMALL INDUSTRIAL	257,949,167	7.7%	277,837,047	42,190	84.8%	35,777	13.7%	40,691	77.94%	116	1.8%
(6) MEDIUM INDUSTRIAL	491,456,958	**6.8%**	524,679,448	93,066	74.2%	69,055	10.7%	76,438	78.36%	192	**2.9%**
(7) LARGE INDUSTRIAL	643,319,737	**3.6%**	666,286,252	93,891	79.8%	74,925	5.6%	79,112	96.14%	232	3.5%
(8) ELI 2P-RTP											
(9) MUNICIPAL	55,845,030	**2.4%**	57,204,049	8,789	99.9%	8,780	4.2%	9,151	71.36%	28	
(10) UNMETERED	78,143,044	8.2%	84,574,217	41,597	25.0%	10,399	13.9%	11,845	81.51%	31	0.5%
(11) SUB-TOTAL	**9,861,845,316**	**7.6%**	**10,612,801,948**	**2,315,749**	**88.1%**	**2,041,094**	**12.64%**	**2,299,116**	**52.69%**	**6,570**	**100.0%**
(12) BOWATER MERSEY	0	N/A	0	0	N/A	0	N/A	0	N/A	-	
(13) GEN.REPL./LOAD FOLL.											
(8) BUTU											
(14) REAL TIME PRICING											
(15) ELIADC											
(16) Shore Power											
EBS/RTR											
Below The Line											
(16) TOTAL	**10,796,412,017**	**7.2%**	**11,571,680,069**	**2,573,664**	**83.2%**	**2,141,546**	**N/A**	**2,404,875**	**54.93%**	**6,889**	**6,690**
GL, LI and Municipal Classes Combined	**1,062,931,551**	**4.0%**	**1,105,772,813**	**163,540**	**78.6%**	**128,498**	**5.6%**	**136,068**	92.77%	**400**	**6.1%**

Large Customer Rate Class Load Disaggregation by Voltage-based Service Levels

			422,729,239								
EHV											
LIR	**217,317,521**	**2.4%**	**222,606,059**	**33,243**	**56.0%**	**18,609**	**4.2%**	**19,391**	**131.1%**	**61.4**	**15.4%**
HV											
LIR HV	149,380,856	2.4%	153,016,119	24,113	83.9%	20,237	4.2%	21,087	82.8%	55.0	**13.8%**
Municipal class HV	45,987,920	2.4%	47,107,060	11,063	92.7%	10,260	4.2%	10,691	50.3%	27.0	**6.8%**
Total	**195,368,776**	**2.4%**	**200,123,180**	**35,175**	**86.7%**	**30,497**	**4.2%**	**31,778**	**71.9%**	**81.9**	**20.6%**
3 Phase Distribution (> 2 MVA)											
LIR (other than EHV and HV)	236,489,152	**5.4%**	249,190,023	41,773	72.7%	30,350	7.5%	32,613	**87.2%**	115.5	**29.0%**
Munis (other than HV)	9,857,110	**0.0%**	10,269,137	3,129	N/A	3,129	-6.5%	2,926	**40.1%**	**0.0**	**0.0%**
Large General (whole)	363,766,784	**5.1%**	382,282,513	61,258	73.1%	44,792	6.7%	47,805	**91.3%**	**139.8**	**35.1%**
Total	**610,113,046**	**5.2%**	**641,741,674**	**106,159**	**73.7%**	**78,271**	**6.5%**	**83,344**	**87.9%**	**255.3**	**64.0%**
EHV, HV and 3 Phase Distribution Total	**1,022,799,343**	**4.1%**	**1,064,470,913**	**174,578**	**73.0%**	**127,377**	**5.6%**	**134,513**	**90.34%**	**398.7**	**100.0%**

CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $414.63 per month.

DEMAND CHARGE

The demand charge for this service is made up of the following two components:

(1) Annually adjusted demand-related purchased power cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism, or General Rate Application.

(2) Demand-related fixed generation cost, coming into effect as a result of a General Rate Application.

Demand Charge Components	**$ per kW of billing demand**
Demand-related Purchased Power Cost	$6.252
Demand-related Fixed Generation Cost	$5.452
Total	**$11.704**

Contract Demand requirement is defined as the firm demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third-party supplier.

Billing demand is determined based upon the following formula:

$$\text{Billing demand} = (PR/(1+PR) * \min(CD, CCF * GC)) + (CD - \min(CD, CCF*GC))$$

Where:

PR is Planning Reserve (based on NPCC planning criteria, i.e. 20% or as updated)

GC is the third-party supplier's generating capacity

(a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.

(b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand.

CD is the customer's Contract Demand

CCF is the capacity contribution factor of the third party supplier's generation to the NSPI system, as determined at the beginning of a billing year by NSPI using information provided in accordance with Special Condition 7 of this tariff and in a manner consistent with NSPI's generation planning studies as amended from time to time.

ENERGY CHARGE

The energy charge is made up of the following two components:

(1) Annually adjusted energy-related purchased power and fuel cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism or General Rate Application.

(2) Energy-related fixed generation cost, coming into effect as a result of a General Rate Application.

Energy Charge Components	**cents per kWh**
Energy-related Purchased Power and Fuel Cost	6.984
Energy-related Fixed Generation Cost	2.166
Total	**9.150**

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(d) of the *Electricity Act*, Chapter 25 of the Acts of 2004.

(d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

The tariff is applicable to the *scheduled* backup/top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

(a) The Municipal utility or utilities for which service is being requested.

(b) The year for which service is being requested.

(c) The contract demand (kW) required for backup and top-up service.

(d) The portion of the customer's annual load contracted to be supplied by third-party suppliers or through self-supply.

(e) The names, addresses, contact details and supply arrangements associated with contracted third-party suppliers.

(2) Backup/top-up service will be subscribed on a minimum 12 month, annual-renewable basis, provided that, if a wholesale customer satisfies the requirement of Special Condition 7(d), the backup/top-up service required with respect to the wholesale customer's procured capacity which satisfies the requirement of Special Condition 7(d) shall be subscribed by the customer on a minimum three-year forward basis.

Applications for service with a CCF value greater than zero in the billing demand calculation of the demand charge must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision by March 31st of each year following an application.

Applications for service with a CCF value of zero in the billing demand calculation of the demand charge must be provided to NSPI by no later than September 1st, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision within two months of receipt of such an application.

(3) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.1% for each transformation between the meter and the transmission voltage.

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under the Open Access Transmission Tariff (OATT).

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(7) Unless the following can be demonstrated by the wholesale customer to the satisfaction of NSPI, the CCF shall be attributed a value of zero in the billing demand calculation of the demand charge:

(a) For a third-party generation resource within Nova Scotia (Internal Resource):

(i.) If the Internal Resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the wholesale customer to NSPI, if directed to do so by the Nova Scotia Power System Operator (NSPSO), in the event of a resource adequacy need;

(ii.) If the Internal Resource is non-dispatchable, that it make its full output contracted to, but unused by, the wholesale customer available to deliver energy to NSPI, in the event of a resource adequacy need;

(iii.) The Internal Resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO; and

(iv.) Any export transactions utilizing energy from the Internal Resource will be recallable by the NSPSO, up to the amount contracted to the wholesale customer, for delivery to the NSPI system in the event of a resource adequacy need.

(b) For a third-party generation resource outside of Nova Scotia (External Resource):

(i.) The energy from the External Resource that is contracted to the wholesale customer will be scheduled and delivered to NSPI in the event of a resource adequacy need;

(ii.) The capacity from the External Resource that is contracted to the wholesale customer must be associated with one or more specific external resource assets, or be system-backed import capacity supported by the external control area where the capacity will be afforded the same curtailment priority as the external control area's native load, and be available to the NSPSO in the event of a resource adequacy need;

(iii.) If the capacity from the External Resource that is contracted to the wholesale customer is associated with one or more specific external resource assets, the wholesale customer must provide:

1. The name and location of each external resource asset;
2. For each asset, generator data including documentation of dependable maximum net capacity and NERC Generating Availability Data System data;
3. Documentation demonstrating proof of contractual control of the capacity all the way to each external resource asset providing the capacity; and
4. Letter of attestation or other documentation from the External Resource owner establishing that the capacity from the External Resource is not being used as capacity in any other balancing area.

(iv.) If the capacity from the External Resource will be supported by the external control area, the wholesale customer must provide:

1. Documentation demonstrating that the import capacity will be supported by the external control area and afforded the same curtailment priority as the external control area's native load.
2. Documentation demonstrating that the External Resource has firm transmission from the specific external resource asset or external control area to the NSPI system.

(c) The Internal Resource or External Resource, as applicable, will perform as needed to meet NSPI's reliability requirements.

(d) The capacity derived based on the CCF is procured and available to the wholesale customer on a minimum three-year forward basis, unless this requirement is waived by NSPI.

(8) In the event of a failure by the Internal Resource or External Resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO in accordance with Special Condition 7, above, then the wholesale customer will be required to make payment to NSPI of an amount equal to the costs incurred by NSPI to procure or to self-supply the undelivered energy and/or capacity, as applicable, less the energy charge paid by the wholesale customer to NSPI under this tariff with respect to any such undelivered energy and/or capacity, as applicable. If delivery of an Internal Resource or External Resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NSPI pursuant to Special Condition 7, above, then NSPI and the wholesale customer shall attempt to negotiate an adjustment to the CCF for the Internal Resource or External Resource, as applicable. If NSPI and the wholesale customer are unable to agree on an adjustment to the CCF, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

ADMINISTRATION CHARGE

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of suppliers supplying wholesale customers} * 12}$$

This charge will be $2,487.77 per month.

ENERGY CREDIT

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs of 6.736 cents per kilowatt hour as approved for use with the GRLF rate.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the administration charge.

AVAILABILITY

This tariff is available for use by, independent non-dispatchable electric generators serving the Wholesale Market. The tariff is applicable to scheduled "spill energy," under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to the Open Access Transmission Tariff (OATT) imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service. Spill capacity will be reviewed periodically and adjusted as required.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Proposed Annual Inflation Rate 3.25%

	2025	2026	Variance	
Administration Costs of the BUTU and Spill Tariffs	$57,827.11	$59,706.49	$1,879.38	3.25%
Administrative Charge Under Spill Rate				
Annual Cost (50% of total)	$28,913.56	$29,853.25	$939.69	3.25%
Number of generators	1	1		
Monthly Customer Charge	**$2,409.46**	**$2,487.77**	**$78.31**	3.25%
Customer Charge Under Backup/Top-up Rate				
Annual Cost (50% of total)	$28,913.56	$29,853.25	$939.69	3.25%
Number of customers/Accounts	6	6	-	0.0%
Monthly Customer Charge	**$401.58**	**$414.63**	**$13.05**	3.25%

2026 BUTU Tariff Rate Components

	Marginal Cost-based Rate	Emebeded Cost-based Rate	Variance	Proposed Rate
Capacity Credit				
Ellershouse	32.0%	20.54%	-11.5%	20.54%
Imports	100.0%	0.0%	-100.0%	0.0%
Monthly Customer Charge $/month/customer	**$414.63**	**$414.63**	**$0.00**	**$414.63**
Demand Charge ($/kW per month)				
FAM demand-related	$0.000	$6.252	$6.252	$6.252
Non-FAM demand-related	$13.430	$5.452	($7.979)	$5.452
Total	**$13.430**	**$11.704**	**($1.727)**	**$11.704**
Energy Charge (c/kWh)				
FAM energy-related	6.736	6.984	0.248	6.984
Non-FAM energy-related	0.000	2.166	2.166	2.166
Total	**6.736**	**9.150**	**2.413**	**9.150**

Base Cost of Fuel Cost of Service Allocation of Fuel Expenses among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2026

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11		Cost Allocation Factors															
12			3 CP Demands		Energy Requirement					Purchased Power- Biomass				Maritime Link			Purchased Pc
13														Basic and Supplemental Blocks			
14	Rate Class	R/C Ratios	KW Demand	Relative Shares of Embedded Cost Classes	KWh Energy	Relative Shares of Embedded Cost Classes	kWhs Sales	Fuel Costs before Purchased Power	Imports (allocated on monthly energy requirements)	Bio-fuel Related (allocated on monthly energy requirements)	Energy-related (allocated on annual energy requirements)	Demand-related	Total	Fixed Energy-related	Fixed Demand-related	Total	Fixed Energy-related
15	**FAM Rate Classes (ATL)**																
16	Residential	97.180%	4,353,838	64.027806%	5,644,778,858	49.7998%	5,213,776,964	$220,605,297	$44,140,315	$4,108,568	$3,130,679	$3,446,385	$10,685,632	$52,743,493	$58,084,777	$110,828,271	$4,875,653
17	Small General	103.50%	222,264	3.26862%	382,310,202	3.37%	353,433,715	$14,745,827	$3,171,069	$285,586	$219,195	$175,938	$680,719	$3,685,454	$2,965,231	$6,650,684	$339,058
18	General Demand	104.38%	1,206,116	17.73722%	2,393,510,995	21.12%	2,219,406,397	$91,296,733	$20,577,967	$1,801,772	$1,401,750	$954,731	$4,158,253	$23,561,585	$16,090,863	$39,652,448	$2,164,515
19	Large General	104.38%	137,482	2.02182%	376,587,283	3.32%	358,568,276	$14,102,288	$3,451,531	$289,502	$230,084	$108,827	$628,413	$3,847,369	$1,834,156	$5,681,525	$352,503
20	Small Industrial	104.38%	123,550	1.81693%	274,651,533	2.42%	255,141,808	$10,377,461	$2,422,479	$209,886	$162,174	$97,799	$469,859	$2,740,533	$1,648,287	$4,388,820	$253,321
21	Medium Industrial	104.38%	158,818	2.33558%	467,931,323	4.13%	438,584,616	$17,476,489	$4,259,468	$356,316	$279,641	$125,716	$761,673	$4,747,907	$2,118,795	$6,866,701	$437,755
22	Large Industrial	104.38%	246,525	3.62541%	722,193,823	6.37%	697,602,851	$26,846,935	$6,707,581	$551,396	$437,072	$195,143	$1,183,611	$7,396,747	$3,288,904	$10,685,652	$679,330
23	PHP	104.38%	203,227	2.98867%	829,996,205	7.32%	810,547,200	$30,393,954	$7,924,664	$623,117	$510,890	$160,869	$1,294,877	$8,676,550	$2,711,265	$11,387,815	$798,245
24	Municipal	104.38%	93,931	1.38135%	128,549,631	1.13%	124,528,392	$5,082,900	$975,982	$92,645	$70,502	$74,353	$237,501	$1,178,059	$1,253,133	$2,431,193	$107,946
25	Unmetered	100.00%	31,520	0.46353%	83,275,289	0.73%	77,000,000	$3,105,001	$759,730	$63,255	$49,732	$24,950	$137,937	$845,341	$420,505	$1,265,845	$77,744
26	Total	100.00%	6,777,270	99.66695%	11,303,785,142	99.73%	10,548,590,219	$434,032,883	$94,390,785	$8,382,044	$6,491,719	$5,364,712	$20,238,476	$109,423,038	$90,415,916	$199,838,954	$10,086,071
27																	
28	Purchased Power Allocation Factors.									41.4%	32.1%	26.5121%	100.0%	54.7%	45.3%	100.0%	54.7%
29																	
30	**Non-FAM Rate Classes**																
31	BUTU	100.00%															
32	GRLF	100.00%															
33	1P - RTP	100.00%															
34	ELIADC	100.00%															
35	Shore Power																
36	EBS /RSS																
37	**Total Below-the-line**		178,670	0.3%	159,281,443	0.3%	155,071,055	$11,424,198	$306,483	$25,689	$20,461	$17,927	$64,077	$332,126	$302,135	$634,260	$30,217
38																	
39	**In Province Total**		6,955,940	100.0%	11,463,066,585	100.0%	10,703,661,274	$445,457,081	$94,697,267	$8,407,734	$6,512,181	$5,382,638	$20,302,553	$109,755,163	$90,718,051	$200,473,214	$10,116,289
40																	
41	Exports	100.00%	-		-		-										
42																	
43	Grand Total		6,955,940		11,463,066,585		10,703,661,274	$445,457,081	$94,697,267	$8,407,734	$6,512,181	$5,382,638	$20,302,553	$109,755,163	$90,718,051	$200,473,214	$10,116,289
44																	
45																	

Line #	COLUMN	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
11		Fuel-related Costs from COS														
12		Power other than Biomass and Wind		Purchased Power - Wind												
13				ERIS			NRIS				Total Fuel-related costs before BUTU Capacity Credit, Export Revenues, OM&G, and Foreign Exchange	BUTU Capacity Credit (Allocated demand-related Costs less BUTU payments)		OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs
14	Rate Class	Fixed Demand-related	Total	Energy-related	Demand-related	Total	Energy-related	Demand-related	Total	Total			Export Revenues			
15	**FAM Rate Classes (ATL)**															
16	Residential	$5,353,756	$10,229,409	$8,948,653	$9,682,485	$18,631,138	$30,002,574	$32,308,240	$62,310,814	$80,941,952	$477,430,875	$193,858	$0	$0	$0	$477,624,733
17	Small General	$273,310	$612,367	$614,098	$494,291	$1,108,389	$2,047,064	$1,649,337	$3,696,401	$4,804,790	$30,665,456	$9,896	$0	$0	$0	$30,675,353
18	General Demand	$1,483,118	$3,647,633	$3,887,660	$2,682,278	$6,569,939	$12,928,207	$8,950,150	$21,878,357	$28,448,296	$187,781,329	$53,703	$0	$0	$0	$187,835,033
19	Large General	$169,057	$521,560	$624,955	$305,746	$930,701	$2,066,722	$1,020,205	$3,086,927	$4,017,627	$28,402,944	$6,122	$0	$0	$0	$28,409,065
20	Small Industrial	$151,925	$405,246	$452,497	$274,762	$727,259	$1,503,324	$916,819	$2,420,143	$3,147,402	$21,211,268	$5,501	$0	$0	$0	$21,216,769
21	Medium Industrial	$195,292	$633,048	$776,260	$353,194	$1,129,454	$2,578,183	$1,178,528	$3,756,711	$4,886,165	$34,883,544	$7,071	$0	$0	$0	$34,890,616
22	Large Industrial	$303,143	$982,473	$1,198,054	$548,246	$1,746,300	$3,976,649	$1,829,373	$5,806,022	$7,552,322	$53,958,573	$10,977	$0	$0	$0	$53,969,549
23	PHP	$249,901	$1,048,146	$1,403,954	$451,956	$1,855,910	$4,647,455	$1,508,075	$6,155,530	$8,011,440	$60,060,895	$9,049	$0	$0	$0	$60,069,944
24	Municipal	$115,503	$223,449	$198,971	$208,892	$407,863	$667,341	$697,025	$1,364,366	$1,772,229	$10,723,254	$4,182	$0	$0	$0	$10,727,436
25	Unmetered	$38,759	$116,502	$137,842	$70,096	$207,938	$458,327	$233,895	$692,223	$900,161	$6,285,177	$1,403	$0	$0	$0	$6,286,580
26	Total	$8,333,763	$18,419,834	$18,242,943	$15,071,948	$33,418,031	$60,875,845	$50,291,647	$111,508,333	$144,482,383	$911,403,314	$301,764	$0	$0	$0	$911,705,078
27																
28	Purchased Power Allocation Factors.	45.3%	100.0%	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%							
29																
30	**Non-FAM Rate Classes**															
31	BUTU	[redacted]														
32	GRLF															
33	1P - RTP															
34	ELIADC															
35	Shore Power															
36	EBS /RSS															
37	**Total Below-the-line**	$27,848	$58,066	$52,775	$50,365	$103,140	$172,786	$168,055	$340,841	$443,981	$12,931,065	-$301,764	$0	$0	$0	$12,629,301
38																
39	**In Province Total**	$8,361,611	$18,477,900	$18,295,718	$15,122,313	$33,521,171	$61,048,631	$50,459,702	$111,849,174	$144,926,364	$924,334,379	$0	$0	$0	$0	$924,334,379
40																
41	Exports															
42																
43	Grand Total	$8,361,611	$18,477,900	$18,295,718	$15,122,313	$33,418,031	$61,048,631	$50,459,702	$111,508,333	$144,926,364	$924,334,379	$0	$0	$0	$0	$924,334,379
44																
45																

Line #	COLUMN	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO
10		Fuel Costs used for FAM purposes				FAM Cost Classification					
11						Cost Amount			Unit Cost (cents per kWh)		
12						Demand-related	Energy-related	Total	Demand-related	Energy-related	Total
13	Rate Class	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh						
14	**FAM Rate Classes (ATL)**										
15	Residential	$464,154,224	50.6%	$461,625,864	8.8540	$109,069,502	$368,555,231	$477,624,733	2.09	7.069	9.161
16	Small General	$31,750,160	3.5%	$31,577,210	8.934	$5,568,003	$25,107,349	$30,675,353	1.58	7.104	8.679
17	General Demand	$196,060,028	21.4%	$194,992,042	8.786	$30,214,843	$157,620,190	$187,835,033	1.36	7.102	8.463
18	Large General	$29,653,053	3.2%	$29,491,525	8.225	$3,444,112	$24,964,953	$28,409,065	0.96	6.962	7.923
19	Small Industrial	$22,145,817	2.4%	$22,025,184	8.633	$3,095,094	$18,121,675	$21,216,769	1.21	7.103	8.316
20	Medium Industrial	$36,418,420	4.0%	$36,220,040	8.258	$3,978,596	$30,912,020	$34,890,616	0.91	7.048	7.955
21	Large Industrial	$56,332,789	6.1%	$56,025,931	8.031	$6,175,786	$47,793,763	$53,969,549	0.89	6.851	7.736
22	PHP	$62,700,310	6.8%	$62,358,767	7.693	$5,091,115	$54,978,828	$60,069,944	0.63	6.783	7.411
23	Municipal	$11,197,174	1.2%	$11,136,180	8.943	$2,353,089	$8,374,347	$10,727,436	1.89	6.725	8.614
24	Unmetered	$6,286,580	0.7%	$6,252,336	8.120	$789,608	$5,496,972	$6,286,580	1.03	7.139	8.164
25	Total	$916,698,556	100.0%	$911,705,078	8.643	$169,779,749	$741,925,329	$911,705,078	1.61	7.033	8.643
26						18.6%	81.4%				
27	Purchased Power Allocation Factors.										
28											
29	**Non-FAM Rate Classes**										
30	BUTU	[redacted]									
31	GRLF										
32	1P - RTP										
33	ELIADC										
34	Shore Power										
35	EBS /RSS										
36	**Total Below-the-line**			$12,629,301	8.144	$264,566	$12,364,735	$12,629,301	0.171	7.974	8.144
37											
38	**In Province Total**			$924,334,379	8.636	$170,044,315	$754,290,064	$924,334,379	1.589	7.047	8.636
39											
40	Exports										
41											
42	Grand Total		100.0%	$924,334,379	8.636	$170,044,315	$754,290,064	$924,334,379	1.589	7.047	8.636
43											
44											
45											

Monthly Fuel Cost Allocation

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Purchased Power													
Imports	$4,757,627	$4,589,694	$3,462,924	$11,463,432	$11,169,883	$11,583,281	$8,099,729	$7,009,590	$10,846,749	$12,840,536	$6,018,108	$2,855,712	**$94,697,267**
Biomass													
IPP	$1,933,751	$1,501,824	$1,568,024	$71,916	$1,476,419	$1,440,568	$1,932,636	$1,975,140	$1,562,773	$85,309	$1,604,921	$1,699,971	**$16,853,252**
Comfit	$275,302	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	**$3,449,301**
Total	**$2,209,053**	**$1,774,468**	**$1,910,905**	**$338,372**	**$1,760,529**	**$1,747,854**	**$2,221,955**	**$2,265,821**	**$1,832,245**	**$345,941**	**$1,921,853**	**$1,973,556**	**$20,302,553**
Maritime Link													
ML - NS Block (GWh)	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$200,473,214
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$16,706,101**	**$200,473,214**
	9,146,264												
Regular other than biomass and wind													
IPP	$1,089,522	$1,308,985	$1,789,401	$1,774,269	$1,644,728	$1,527,824	$1,253,560	$1,142,692	$1,514,565	$1,430,960	$1,813,629	$2,167,026	**$18,457,161**
Comfit	$2,870	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	**$20,739**
Total	**$1,092,392**	**$1,310,424**	**$1,791,130**	**$1,775,899**	**$1,646,171**	**$1,529,120**	**$1,254,941**	**$1,144,436**	**$1,516,133**	**$1,432,478**	**$1,815,907**	**$2,168,869**	**$18,477,900**
Wind NRIS													
IPP	$3,389,237	$3,589,681	$4,112,442	$3,528,178	$3,229,511	$2,482,409	$2,309,965	$2,149,334	$3,273,229	$4,362,000	$6,574,920	$8,509,661	**$47,510,568**
Comfit	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	**$63,997,765**
Total	**$9,003,590**	**$9,435,246**	**$11,296,633**	**$9,631,189**	**$8,715,152**	**$7,017,296**	**$6,234,525**	**$5,674,290**	**$7,868,746**	**$8,140,557**	**$13,197,455**	**$15,293,654**	**$111,508,333**
Wind ERIS													
IPP	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	**$33,418,031**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	**$33,418,031**
Grand Total	**$36,378,424**	**$37,074,393**	**$38,794,783**	**$42,436,409**	**$42,848,326**	**$41,117,732**	**$36,709,207**	**$34,716,334**	**$41,020,793**	**$41,623,544**	**$43,371,341**	**$42,786,010**	**$478,877,298**
Plant Fuel Costs													
Plant Fuel Costs	$67,441,935	$54,358,722	$49,574,650	$30,087,598	$22,231,785	$23,382,648	$35,228,716	$35,916,700	$23,184,621	$25,673,066	$33,591,286	$44,785,354	**$445,457,081**
BTL Class Fuel-related costs													
GRLF	[redacted]												
1P - RTP													
PHP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Shore Power	[redacted]												
Total	$666,442	$572,516	$334,043	$672,296	$765,054	$981,238	$1,157,980	$1,506,607	$1,175,360	$872,849	$741,340	$827,467	**$10,273,192**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
ATL-related Fuel costs (net of BTL without BUTU)	$66,775,493	$53,786,205	$49,240,607	$29,415,302	$21,466,732	$22,401,410	$34,070,736	$34,410,093	$22,009,261	$24,800,217	$32,849,946	$43,957,887	**$435,183,889**
Fuel costs before PP													
Domestic	$38,228,651	$31,179,517	$26,920,887	$15,230,729	$10,102,130	$9,371,790	$14,259,027	$14,576,495	$8,810,958	$10,712,877	$16,063,256	$25,148,979	$220,605,297
Small General	$2,328,777	$1,884,233	$1,684,765	$957,025	$718,176	$759,918	$1,179,382	$1,181,806	$734,372	$796,603	$1,074,465	$1,446,305	$14,745,827
General	$13,213,118	$10,476,936	$9,942,469	$5,814,496	$4,433,710	$5,202,359	$7,949,988	$8,023,624	$5,110,445	$5,595,799	$7,027,357	$8,506,432	$91,296,733
Large General	$1,696,610	$1,406,484	$1,328,990	$921,409	$757,067	$900,952	$1,495,678	$1,476,239	$977,867	$957,757	$1,034,918	$1,148,316	$14,102,288
Small Industrial	$1,423,129	$1,111,387	$1,030,696	$669,777	$567,747	$718,259	$995,536	$910,709	$586,032	$595,351	$776,133	$992,704	$10,377,461
Medium Industrial	$2,187,197	$1,732,967	$1,713,093	$1,158,826	$1,014,272	$1,215,616	$1,690,455	$1,604,876	$1,111,130	$1,151,069	$1,410,496	$1,486,492	$17,476,489
Large Industrial	$3,259,098	$2,560,613	$2,417,917	$1,782,721	$1,594,382	$1,809,538	$2,544,362	$2,832,908	$1,852,198	$1,927,664	$2,172,371	$2,093,161	$26,846,935
PHP	$2,973,113	$2,276,438	$3,223,246	$2,268,484	$1,863,211	$1,956,097	$3,210,697	$3,031,656	$2,286,771	$2,522,785	$2,556,281	$2,225,176	$30,393,954
Municipal	$961,984	$736,135	$630,118	$326,255	$163,163	$173,355	$313,775	$304,865	$219,045	$271,679	$418,555	$563,973	$5,082,900
Unmetered													
BUTU													
Total	**$66,775,493**	**$53,786,205**	**$49,240,607**	**$29,415,302**	**$21,466,732**	**$22,401,410**	**$34,070,736**	**$34,410,093**	**$22,009,261**	**$24,800,217**	**$32,849,946**	**$43,957,887**	**$435,183,889**
Exports													
Domestic	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Medium Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PHP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered													
BUTU													
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Imports													
Domestic	$2,723,719	$2,660,616	$1,893,254	$5,935,564	$5,256,488	$4,845,949	$3,389,837	$2,969,340	$4,342,274	$5,546,689	$2,942,788	$1,633,796	$44,140,315
Small General	$165,921	$160,786	$118,484	$372,962	$373,692	$392,937	$280,378	$240,743	$361,918	$412,448	$196,842	$93,959	$3,171,069
General	$941,410	$894,020	$699,220	$2,265,966	$2,307,013	$2,690,027	$1,889,972	$1,634,471	$2,518,563	$2,897,275	$1,287,411	$552,618	$20,577,967
Large General	$120,880	$120,018	$93,463	$359,082	$393,928	$465,863	$355,572	$300,721	$481,919	$495,887	$189,597	$74,600	$3,451,531
Small Industrial	$101,395	$94,837	$72,485	$261,018	$295,419	$371,396	$236,671	$185,518	$288,812	$308,248	$142,188	$64,491	$2,422,479
Medium Industrial	$155,834	$147,878	$120,476	$451,606	$527,761	$628,569	$401,876	$326,925	$547,594	$595,976	$258,403	$96,570	$4,259,468
Large Industrial	$232,205	$218,503	$170,044	$694,744	$829,612	$935,673	$604,878	$577,084	$912,813	$998,065	$397,978	$135,982	$6,707,581
PHP	$211,829	$194,253	$226,680	$884,050	$969,493	$1,011,455	$763,288	$617,571	$1,126,982	$1,306,195	$468,311	$144,558	$7,924,664
Municipal	$68,540	$62,816	$44,314	$127,145	$84,899	$89,638	$74,595	$62,103	$107,951	$140,664	$76,679	$36,638	$975,982
Unmetered													
BUTU													
Total	$4,757,627	$4,589,694	$3,462,924	$11,463,432	$11,169,883	$11,583,281	$8,099,729	$7,009,590	$10,846,749	$12,840,536	$6,018,108	$2,855,712	$94,697,267
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	12,236,372	11,899,369	16,036,280	16,447,820	13,090,652	418,181	13,292,610	14,132,701	139,470,614
Relative Share	11.5%	8.9%	9.3%	0.3%	8.8%	8.5%	11.5%	11.8%	9.4%	0.3%	9.5%	10.1%	100.0%
Bio-fuel Apportioned	$970,018	$751,630	$783,969	$21,251	$737,648	$717,332	$966,718	$991,527	$789,146	$25,209	$801,321	$851,964	$8,407,734
Domestic	$555,331	$435,715	$428,612	$11,004	$347,133	$300,101	$404,584	$420,022	$315,919	$10,890	$391,837	$487,422	$4,108,568
Small General	$33,829	$26,331	$26,823	$691	$24,678	$24,334	$33,464	$34,054	$26,331	$810	$26,210	$28,031	$285,586
General	$191,941	$146,409	$158,296	$4,201	$152,353	$166,589	$225,572	$231,201	$183,236	$5,688	$171,421	$164,866	$1,801,772
Large General	$24,646	$19,655	$21,159	$666	$26,015	$28,850	$42,438	$42,538	$35,062	$974	$25,245	$22,256	$289,502
Small Industrial	$20,673	$15,531	$16,410	$484	$19,509	$23,000	$28,247	$26,242	$21,012	$605	$18,933	$19,240	$209,886
Medium Industrial	$31,772	$24,217	$27,274	$837	$34,853	$38,926	$47,965	$46,245	$39,840	$1,170	$34,407	$28,810	$356,316
Large Industrial	$47,343	$35,783	$38,496	$1,288	$54,787	$57,945	$72,193	$81,630	$66,411	$1,959	$52,991	$40,568	$551,396
PHP	$43,189	$31,812	$51,318	$1,639	$64,024	$62,638	$91,100	$87,357	$81,993	$2,564	$62,356	$43,127	$623,117
Municipal	$13,974	$10,287	$10,032	$236	$5,607	$5,551	$8,903	$8,785	$7,854	$276	$10,210	$10,931	$92,645
Unmetered													
BUTU													
Total	**$970,018**	**$751,630**	**$783,969**	**$21,251**	**$737,648**	**$717,332**	**$966,718**	**$991,527**	**$789,146**	**$25,209**	**$801,321**	**$851,964**	**$8,407,734**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Domestic	$41,507,701	$34,275,849	$29,242,754	$21,177,297	$15,705,751	$14,517,840	$18,053,448	$17,965,856	$13,469,151	$16,270,455	$19,397,881	$27,270,197	$268,854,180
Small General	$2,528,527	$2,071,349	$1,830,072	$1,330,678	$1,116,546	$1,177,189	$1,493,224	$1,456,603	$1,122,621	$1,209,861	$1,297,517	$1,568,295	$18,202,482
General	$14,346,469	$11,517,365	$10,799,985	$8,084,663	$6,893,076	$8,058,974	$10,065,532	$9,889,296	$7,812,244	$8,498,762	$8,486,189	$9,223,916	$113,676,472
Large General	$1,842,136	$1,546,157	$1,443,613	$1,281,157	$1,177,010	$1,395,665	$1,893,688	$1,819,498	$1,494,848	$1,454,618	$1,249,760	$1,245,171	$17,843,321
Small Industrial	$1,545,197	$1,221,756	$1,119,592	$931,279	$882,675	$1,112,655	$1,260,454	$1,122,469	$895,857	$904,205	$937,254	$1,076,435	$13,009,826
Medium Industrial	$2,374,803	$1,905,061	$1,860,843	$1,611,269	$1,576,886	$1,883,111	$2,140,296	$1,978,046	$1,698,564	$1,748,215	$1,703,306	$1,611,872	$22,092,273
Large Industrial	$3,538,646	$2,814,899	$2,626,457	$2,478,753	$2,478,781	$2,803,156	$3,221,434	$3,491,623	$2,831,422	$2,927,689	$2,623,340	$2,269,711	$34,105,911
PHP	$3,228,131	$2,502,503	$3,501,244	$3,154,173	$2,896,728	$3,030,190	$4,065,084	$3,736,584	$3,495,745	$3,831,544	$3,086,948	$2,412,860	$38,941,734
Municipal	$1,044,498	$809,238	$684,464	$453,635	$253,669	$268,544	$397,273	$375,753	$334,850	$412,619	$505,444	$611,542	$6,151,528
Unmetered													
BUTU													
Total	**$72,503,138**	**$59,127,530**	**$53,487,499**	**$40,899,985**	**$33,374,262**	**$34,702,023**	**$43,137,184**	**$42,411,210**	**$33,645,156**	**$37,665,963**	**$39,669,375**	**$47,665,563**	**$538,288,890**
Domestic	6.38	5.62	5.08	4.76	4.35	4.96	5.65	5.59	4.88	4.97	4.49	4.52	5.16
Small General	6.38	5.62	5.08	4.76	4.35	4.96	5.64	5.58	4.88	4.97	4.49	4.52	5.15
General	6.36	5.60	5.06	4.75	4.34	4.94	5.63	5.57	4.86	4.95	4.48	4.51	5.12
Large General	6.19	5.45	4.93	4.62	4.23	4.82	5.49	5.44	4.74	4.83	4.36	4.39	4.98
Small Industrial	6.35	5.59	5.06	4.74	4.33	4.94	5.62	5.56	4.86	4.94	4.47	4.50	5.10
Medium Industrial	6.29	5.54	5.01	4.70	4.29	4.90	5.57	5.52	4.82	4.90	4.43	4.46	5.04
Large Industrial	6.09	5.37	4.85	4.56	4.17	4.75	5.42	5.37	4.68	4.76	4.29	4.33	4.89
PHP	6.02	5.30	4.79	4.51	4.12	4.70	5.36	5.32	4.63	4.71	4.24	4.28	4.80
Municipal	6.07	5.35	4.83	4.54	4.15	4.73	5.40	5.35	4.66	4.74	4.28	4.31	4.94
Unmetered													
BUTU													
Total	**6.34**	**5.59**	**5.04**	**4.73**	**4.32**	**4.92**	**5.61**	**5.56**	**4.84**	**4.92**	**4.45**	**4.50**	**5.10**
Maritime Link	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$109,755,163
Energy													
Domestic	$5,302,030	$5,000,457	$4,735,775	$4,304,183	$3,826,405	$3,827,825	$3,874,458	$3,661,520	$3,950,885	$4,472,421	$5,232,717	$4,554,818	$52,743,493
Small General	$320,411	$312,939	$297,573	$305,991	$310,267	$316,604	$314,126	$305,179	$293,785	$299,158	$300,931	$308,489	$3,685,454
General	$1,781,587	$1,846,777	$1,807,934	$1,889,057	$2,124,069	$2,134,168	$2,132,693	$2,123,718	$2,063,718	$1,956,596	$1,769,923	$1,931,343	$23,561,585
Large General	$239,170	$246,855	$286,499	$322,561	$367,850	$401,514	$392,387	$406,367	$353,219	$288,148	$238,929	$303,871	$3,847,369
Small Industrial	$188,990	$191,448	$208,257	$241,898	$293,258	$267,251	$242,068	$243,534	$219,564	$216,095	$206,551	$221,619	$2,740,533
Medium Industrial	$294,688	$318,201	$360,320	$432,148	$496,324	$453,801	$426,579	$461,746	$424,512	$392,718	$309,293	$377,578	$4,747,907
Large Industrial	$435,428	$449,119	$554,311	$679,313	$738,816	$683,032	$752,992	$769,708	$710,918	$604,843	$435,521	$582,744	$7,396,747
PHP	$387,105	$598,706	$705,352	$793,852	$798,654	$861,909	$805,819	$950,301	$930,397	$711,734	$462,990	$669,731	$8,676,550
Municipal	$125,179	$117,042	$101,444	$69,518	$70,779	$84,233	$81,034	$91,027	$100,194	$116,536	$117,345	$103,728	$1,178,059
Unmetered	$55,140	$55,230	$66,632	$78,764	$83,757	$76,949	$74,123	$89,077	$73,577	$72,070	$52,828	$67,196	$845,341
BUTU	$16,535	$9,489	$22,166	$28,977	$36,086	$38,977	$49,984	$44,088	$25,495	$15,944	$19,237	$25,148	$332,126
Total	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$109,755,163**
BIOMASS	$678,347.67	$559,983.80	$616,975.41	$173,617.30	$560,007.72	$564,190.92	$687,217.42	$697,650.99	$571,076.32	$175,594.26	$613,469.50	$614,049.62	$6,512,181
Energy													
Domestic	$393,234	$306,155	$319,459	$81,703	$234,283	$236,121	$291,113	$279,290	$246,686	$85,864	$350,975	$305,795	$3,130,679
Small General	$23,764	$19,160	$20,073	$5,808	$18,997	$19,530	$23,602	$23,278	$18,343	$5,743	$20,184	$20,711	$219,195
General	$132,134	$113,070	$121,957	$35,859	$130,053	$131,647	$160,243	$161,991	$128,855	$37,564	$118,714	$129,664	$1,401,750
Large General	$17,738	$15,114	$19,326	$6,123	$22,523	$24,768	$29,483	$30,996	$22,054	$5,532	$16,026	$20,401	$230,084
Small Industrial	$14,017	$11,721	$14,048	$4,592	$17,956	$16,485	$18,188	$18,576	$13,709	$4,149	$13,854	$14,879	$162,174
Medium Industrial	$21,856	$19,482	$24,306	$8,203	$30,389	$27,993	$32,052	$35,221	$26,506	$7,540	$20,745	$25,349	$279,641
Large Industrial	$32,294	$27,498	$37,392	$12,895	$45,236	$42,133	$56,577	$58,711	$44,388	$11,612	$29,212	$39,123	$437,072
PHP	$28,710	$36,656	$47,581	$15,069	$48,900	$53,167	$60,546	$72,486	$58,092	$13,664	$31,054	$44,963	$510,890
Municipal	$9,284	$7,166	$6,843	$1,320	$4,334	$5,196	$6,089	$6,943	$6,256	$2,237	$7,871	$6,964	$70,502
Unmetered	$4,090	$3,381	$4,495	$1,495	$5,128	$4,747	$5,569	$6,795	$4,594	$1,384	$3,543	$4,511	$49,732
BUTU	$1,226	$581	$1,495	$550	$2,209	$2,404	$3,756	$3,363	$1,592	$306	$1,290	$1,688	$20,461
Total	**$678,348**	**$559,984**	**$616,975**	**$173,617**	**$560,008**	**$564,191**	**$687,217**	**$697,651**	**$571,076**	**$175,594**	**$613,469**	**$614,050**	**$6,512,181**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Regular other than biomass and wind	$598,063.06	$717,431.71	$980,608.79	$972,269.89	$901,246.56	$837,163.11	$687,055.89	$626,556.24	$830,052.89	$784,253.60	$994,173.59	$1,187,413.32	$10,116,289
Energy													
Domestic	$346,693	$392,235	$507,742	$457,545	$377,043	$350,363	$291,044	$250,829	$358,556	$383,491	$568,782	$591,329	$4,875,653
Small General	$20,951	$24,547	$31,904	$32,528	$30,573	$28,979	$23,597	$20,906	$26,662	$25,652	$32,710	$40,050	$339,058
General	$116,496	$144,861	$193,836	$200,811	$209,300	$195,342	$160,205	$145,483	$187,289	$167,770	$192,386	$250,737	$2,164,515
Large General	$15,639	$19,363	$30,717	$34,289	$36,247	$36,751	$29,476	$27,838	$32,056	$24,707	$25,971	$39,450	$352,503
Small Industrial	$12,358	$15,017	$22,328	$25,714	$28,897	$24,462	$18,184	$16,683	$19,926	$18,529	$22,452	$28,772	$253,321
Medium Industrial	$19,269	$24,960	$38,631	$45,938	$48,906	$41,537	$32,044	$31,631	$38,526	$33,674	$33,619	$49,019	$437,755
Large Industrial	$28,472	$35,229	$59,430	$72,213	$72,801	$62,518	$56,564	$52,728	$64,518	$51,863	$47,340	$75,655	$679,330
PHP	$25,312	$46,962	$75,624	$84,388	$78,697	$78,891	$60,532	$65,099	$84,437	$61,028	$50,326	$86,948	$798,245
Municipal	$8,185	$9,181	$10,876	$7,390	$6,974	$7,710	$6,087	$6,236	$9,093	$9,993	$12,755	$13,466	$107,946
Unmetered	$3,606	$4,332	$7,144	$8,373	$8,253	$7,043	$5,568	$6,102	$6,677	$6,180	$5,742	$8,724	$77,744
BUTU	$1,081	$744	$2,376	$3,080	$3,556	$3,568	$3,755	$3,020	$2,314	$1,367	$2,091	$3,265	$30,217
Total	**$598,063**	**$717,432**	**$980,609**	**$972,270**	**$901,247**	**$837,163**	**$687,056**	**$626,556**	**$830,053**	**$784,254**	**$994,174**	**$1,187,413**	**$10,116,289**
Wind NRIS	$4,929,289.59	$5,165,612.74	$6,184,685.79	$5,272,887.31	$4,771,375.04	$3,841,832.14	$3,413,280.33	$3,106,562.51	$4,307,984.78	$4,456,795.59	$7,225,348.69	$8,372,976.41	$61,048,631
Energy													
Domestic	$2,857,477	$2,824,150	$3,202,322	$2,481,393	$1,996,139	$1,607,855	$1,445,903	$1,243,649	$1,860,908	$2,179,323	$4,133,732	$4,169,722	$30,002,574
Small General	$172,682	$176,741	$201,218	$176,406	$161,858	$132,988	$117,228	$103,655	$138,376	$145,774	$237,729	$282,407	$2,047,064
General	$960,169	$1,043,020	$1,222,521	$1,089,055	$1,108,073	$896,444	$795,897	$721,329	$972,032	$953,411	$1,398,200	$1,768,054	$12,928,207
Large General	$128,899	$139,418	$193,730	$185,959	$191,898	$168,653	$146,434	$138,024	$166,370	$140,409	$188,748	$278,180	$2,066,722
Small Industrial	$101,854	$108,126	$140,823	$139,456	$152,985	$112,257	$90,337	$82,717	$103,417	$105,299	$163,171	$202,881	$1,503,324
Medium Industrial	$158,819	$179,713	$243,648	$249,136	$258,919	$190,616	$159,194	$156,834	$199,949	$191,364	$244,334	$345,655	$2,578,183
Large Industrial	$234,670	$253,653	$374,824	$391,629	$385,422	$286,903	$281,008	$261,434	$334,850	$294,728	$344,052	$533,475	$3,976,649
PHP	$208,626	$338,136	$476,958	$457,662	$416,638	$362,040	$300,723	$322,773	$438,227	$346,814	$365,752	$613,107	$4,647,455
Municipal	$67,464	$66,103	$68,596	$40,078	$36,924	$35,381	$30,241	$30,918	$47,193	$56,786	$92,700	$94,958	$667,341
Unmetered	$29,717	$31,193	$45,056	$45,408	$43,694	$32,322	$27,662	$30,255	$34,655	$35,118	$41,733	$61,514	$458,327
BUTU	$8,911	$5,359	$14,989	$16,705	$18,825	$16,372	$18,653	$14,975	$12,008	$7,769	$15,197	$23,022	$172,786
Total	**$4,929,290**	**$5,165,613**	**$6,184,686**	**$5,272,887**	**$4,771,375**	**$3,841,832**	**$3,413,280**	**$3,106,563**	**$4,307,985**	**$4,456,796**	**$7,225,349**	**$8,372,976**	**$61,048,631**
Wind ERIS	$1,428,737.80	$1,783,942.56	$1,985,760.83	$1,380,426.49	$1,560,587.52	$1,387,359.23	$1,200,053.03	$1,049,025.08	$1,232,278.83	$1,181,425.01	$2,032,201.40	$2,073,920.51	$18,295,718
Energy													
Domestic	$828,230	$975,319	$1,028,192	$649,621	$652,883	$580,627	$508,356	$419,956	$532,304	$577,704	$1,162,653	$1,032,807	$8,948,653
Small General	$50,051	$61,037	$64,607	$46,183	$52,939	$48,024	$41,216	$35,002	$39,582	$38,642	$66,864	$69,950	$614,098
General	$278,302	$360,207	$392,524	$285,111	$362,421	$323,723	$279,824	$243,579	$278,045	$252,734	$393,258	$437,933	$3,887,660
Large General	$37,361	$48,148	$62,202	$48,683	$62,765	$60,904	$51,484	$46,608	$47,589	$37,220	$53,087	$68,903	$624,955
Small Industrial	$29,522	$37,341	$45,215	$36,509	$50,037	$40,538	$31,761	$27,932	$29,582	$27,913	$45,893	$50,252	$452,497
Medium Industrial	$46,033	$62,064	$78,230	$65,223	$84,686	$68,835	$55,970	$52,960	$57,195	$50,727	$68,722	$85,616	$776,260
Large Industrial	$68,018	$87,599	$120,348	$102,527	$126,061	$103,606	$98,798	$88,281	$95,782	$78,128	$96,768	$132,138	$1,198,054
PHP	$60,470	$116,775	$153,140	$119,814	$136,271	$130,739	$105,729	$108,994	$125,353	$91,935	$102,871	$151,862	$1,403,954
Municipal	$19,554	$22,829	$22,025	$10,492	$12,077	$12,777	$10,632	$10,440	$13,499	$15,053	$26,073	$23,520	$198,971
Unmetered	$8,613	$10,772	$14,466	$11,888	$14,291	$11,672	$9,725	$10,217	$9,913	$9,309	$11,738	$15,237	$137,842
BUTU	$2,583	$1,851	$4,812	$4,373	$6,157	$5,912	$6,558	$5,057	$3,435	$2,059	$4,274	$5,702	$52,775
Total	**$1,428,738**	**$1,783,943**	**$1,985,761**	**$1,380,426**	**$1,560,588**	**$1,387,359**	**$1,200,053**	**$1,049,025**	**$1,232,279**	**$1,181,425**	**$2,032,201**	**$2,073,921**	**$18,295,718**

Monthly Energy Allocators

Rate Class	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
kWh requirements													
ATL													
Domestic Total	707,116,004	662,646,274	625,765,329	481,109,226	389,926,477	315,832,492	344,330,438	345,113,243	297,672,902	353,637,738	468,685,690	652,943,045	5,644,778,858
Small General	43,075,431	40,044,871	39,161,684	30,230,565	27,720,465	25,609,499	28,480,010	27,980,457	24,810,312	26,296,289	31,350,205	37,550,416	382,310,202
General	244,403,273	222,662,284	231,108,747	183,668,663	171,134,295	175,321,259	191,978,244	189,967,402	172,653,292	184,720,285	205,040,721	220,852,532	2,393,510,995
Large General	31,382,222	29,891,458	30,891,848	29,105,540	29,221,607	30,362,399	36,118,000	34,951,453	33,036,649	31,616,065	30,196,319	29,813,722	376,587,283
Small Industrial	26,323,632	23,619,890	23,958,128	21,156,943	21,914,164	24,205,562	24,040,437	21,561,950	19,798,742	19,652,860	22,645,635	25,773,589	274,651,533
Medium Industrial	40,456,616	36,830,070	39,820,167	36,605,073	39,149,327	40,966,679	40,821,513	37,997,064	37,538,851	37,997,398	41,154,755	38,593,810	467,931,323
Large Industrial	60,283,593	54,419,718	56,203,514	56,312,715	61,540,663	60,982,054	61,441,880	67,071,964	62,575,410	63,633,209	63,384,353	54,344,751	722,193,823
PHP	54,993,729	48,380,250	74,923,076	71,657,003	71,917,020	65,921,139	77,532,680	71,777,511	77,257,186	83,278,469	74,585,898	57,772,243	829,996,205
Municipal	17,793,843	15,644,788	14,646,832	10,305,750	6,297,827	5,842,110	7,577,118	7,217,995	7,400,291	8,968,255	12,212,395	14,642,427	128,549,631
Unmetered	[redacted]												
BUTU													
Total	1,235,147,403	1,143,097,507	1,144,578,344	929,172,442	828,582,358	754,935,070	822,748,406	814,693,714	743,569,610	818,668,306	958,479,362	1,141,278,810	11,334,951,333
Fuel Cost Allocators													
ATL													
Domestic	57.24952%	57.97%	54.67%	51.78%	47.06%	41.84%	41.85%	42.36%	40.03%	43.20%	48.90%	57.21%	49.80%
Small General	3.48747%	3.50%	3.42%	3.25%	3.35%	3.39%	3.46%	3.43%	3.34%	3.21%	3.27%	3.29%	3.37%
General	19.78738%	19.48%	20.19%	19.77%	20.65%	23.22%	23.33%	23.32%	23.22%	22.56%	21.39%	19.35%	21.12%
Large General	2.54077%	2.61%	2.70%	3.13%	3.53%	4.02%	4.39%	4.29%	4.44%	3.86%	3.15%	2.61%	3.32%
Small Industrial	2.13121%	2.07%	2.09%	2.28%	2.64%	3.21%	2.92%	2.65%	2.66%	2.40%	2.36%	2.26%	2.42%
Medium Industrial	3.27545%	3.22%	3.48%	3.94%	4.72%	5.43%	4.96%	4.66%	5.05%	4.64%	4.29%	3.38%	4.13%
Large Industrial	4.88068%	4.76%	4.91%	6.06%	7.43%	8.08%	7.47%	8.23%	8.42%	7.77%	6.61%	4.76%	6.37%
PHP	4.45%	4.23%	6.55%	7.71%	8.68%	8.73%	9.42%	8.81%	10.39%	10.17%	7.78%	5.06%	7.32%
Municipal	1.44063%	1.37%	1.28%	1.11%	0.76%	0.77%	0.92%	0.89%	1.00%	1.10%	1.27%	1.28%	1.13%
Unmetered	[redacted]												
BUTU													
Total	100.00000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

BUTU Capacity Credit Calc.

	Installed Capacity	Capacity Credit	Approved Contract Demands (kWs)	FAM-related Demand Charge	Gross Demand Payment	Net Demand payment bfr Credits	Capacity Credit
Ellershouse	23,500	20.5%	7,549	$6.252	[redacted]		
Imports	[redacted]	0%	[redacted]	$6.252			
Total							-$301,764

Biomass Calculations

($ in millions)	2026	
Capital	[redacted]	[redacted]
Fuel		
Operating		
Total	54.0	100.0%

Data from M05473 Exhibit N-3 CA IR-065P Confidential from the COSS Proceeding

Annual Peak of ATL	2,356,954
Annual Energy Requirement of ATL	11,303,785,142

System Coincident Load Factor **54.748044%**

Rate Base	**Average**	**2025**	**2026**
Steam Plant	$ 481,584	$ 543,265	$ 419,903
Steam Plant - CWIP	$ 4,559	$ 4,744	$ 4,374
Steam Environmental & Fuel Conversion	$ 360,906	$ 369,394	$ 352,418
Steam Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Hydro Plant	$ 644,461	$ 603,548	$ 685,374
Hydro Plant - CWIP	$ 44,561	$ 55,299	$ 33,823
Hydro Environmental & Fuel Conversion	$ 10,643	$ 10,402	$ 10,884
Hydro Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Wind Plant	$ 163,575	$ 168,639	$ 158,510
Wind Plant - CWIP	$ 196	$ 196	$ 196
Gas Turbine Plant	$ 67,260	$ 58,451	$ 76,069
Gas Turbine Plant - CWIP	$ 881	$ 1,070	$ 692
Gas Environmental & Fuel Conversion	$ -	$ -	$ -
Gas Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
LM6000 Plant	$ 93,707	$ 94,612	$ 92,802
LM6000 Plant - CWIP	$ 30	$ 0	$ 60
LM6000 Environmental & Fuel Conversion	$ -	$ -	$ -
LM6000 Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
ECEI Batteries Plant	$ 145,582	$ 119,318	$ 171,846
ECEI Batteries CWIP	$ 15,185	$ 30,370	$ (0)
Generation-related Trans Assets Plant	$ 58,575	$ 58,575	$ 58,575
Generation-related Trans Assets CWIP	$ -	$ -	$ -
Total Generation Exclusing Solar	**$ 2,091,705**	**$ 2,117,885**	**$ 2,065,526**
DISTRIBUTION	$ 40,929	$ 44,376	$ 37,483
TRANSMISSION	$ 2,906	$ 3,104	$ 2,708
DISTRIBUTION/ TRANSMISSION COMMUNICATION	$ 34,964	$ 32,676	$ 37,252
DISTRIBUTION/ TRANSMISSION NON-COMMUNICATION	$ 48,211	$ 41,591	$ 54,831
RETAIL	$ 42,983	$ 46,109	$ 39,858
NON-FUNCTIONALIZED	$ 292,481	$ 287,072	$ 297,891
General Property Plant	$ 462,475	$ 454,929	$ 470,022
General Property Plant - CWIP	$ 14,812	$ 10,022	$ 19,601
Total General Plant	**$ 477,287**	**$ 464,951**	**$ 489,623**
Total System Plant in Service	$ 4,480,567		
Direct Plant in Service (Solar)	$ 1,285		

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$ 847,049	$ 847,049	$ -	$ -	$ (463,743)	$ 463,743	$ -	$ 383,306	$ 463,743	$ -
Hydro Plant	$ 699,665	$ 699,665	$ -	$ -	$ (383,053)	$ 383,053	$ -	$ 316,612	$ 383,053	$ -
Wind Plant	$ 163,771	$ 163,771	$ -	$ -	$ (89,661)	$ 89,661	$ -	$ 74,110	$ 89,661	$ -
LM6000 Plant	$ 93,737	$ 93,737	$ -	$ -	$ (51,319)	$ 51,319	$ -	$ 42,418	$ 51,319	$ -
Gas Turbine Plant - Other	$ 68,141	$ 68,141	$ -	$ -	$ (37,306)	$ 37,306	$ -	$ 30,835	$ 37,306	$ -
Batteries	$ 160,767	$ 160,767	$ -	$ -	$ (88,017)	$ 88,017	$ -	$ 72,750	$ 88,017	$ -
Radial to Generation Transmission	$ 58,575	$ 58,575	$ -	$ -	$ (32,069)	$ 32,069	$ -	$ 26,506	$ 32,069	$ -
Total Generation Plant	$ 2,091,705	$ 2,091,705	$ -	$ -	$ (1,145,168)	$ 1,145,168	$ -	$ 946,538	$ 1,145,168	$ -
General Property Plant -generation-related	$ 143,497.6	$ 143,498	$ -	$ -	$ (78,562)	$ 78,562	$ -	$ 64,935	$ 78,562	$ -
Total Generation Plant in Service	$ 2,235,203	$ 2,235,203	$ -	$ -	$ (1,223,730)	$ 1,223,730	$ -	$ 1,011,473	$ 1,223,730	$ -
Rate Base Factors Applicable to Base Cost of Fuel Classification								**45.252%**	**54.748%**	

Data Inputs

Category	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Annual
Plant Fuel Costs	$67,441,935	$54,358,722	$49,574,650	$30,087,598	$22,231,785	$23,382,648	$35,228,716	$35,916,700	$23,184,621	$25,673,066	$33,591,286	$44,785,354	$445,457,081
Maritime Link													
ML - NS Block	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$200,473,214
ML - Supp Block													
ML - Surplus													
Total	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$200,473,214
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$1,089,522	$1,308,985	$1,789,401	$1,774,269	$1,644,728	$1,527,824	$1,253,560	$1,142,692	$1,514,565	$1,430,960	$1,813,629	$2,167,026	$18,457,161
Purchased Power - Biomass	$1,933,751	$1,501,824	$1,568,024	$71,916	$1,476,419	$1,440,568	$1,932,636	$1,975,140	$1,562,773	$85,309	$1,604,921	$1,699,971	$16,853,252
Non-Wind Purchases	$3,023,273	$2,810,809	$3,357,425	$1,846,185	$3,121,147	$2,968,392	$3,186,196	$3,117,832	$3,077,338	$1,516,269	$3,418,550	$3,866,997	$35,310,413
Wind Purchases													
Purchased Power Wind - NRIS	$3,389,237	$3,589,681	$4,112,442	$3,528,178	$3,229,511	$2,482,409	$2,309,965	$2,149,334	$3,273,229	$4,362,000	$6,574,920	$8,509,661	$47,510,568
Purchased Power Wind - ERIS	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	$33,418,031
Purchased Power Wind	$ 5,998,896.96	$ 6,848,140.25	$ 7,739,532.09	$ 6,049,595.00	$ 6,080,000.73	$ 5,016,489.41	$ 4,501,921.10	$ 4,065,430.31	$ 5,524,047.11	$ 6,519,930.62	$ 10,286,835.84	$ 12,297,779.11	$80,928,599
COMFIT													
Wind Generation (NRIS)	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	$63,997,765
Wind Generation (ERIS)													
Biomass/ Biogas	$ 275,302.28	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	$3,449,301
Other	$ 2,869.65	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	$20,739
Total Comfit	$ 5,892,525	$ 6,119,648	$ 7,528,801	$ 6,371,096	$ 5,771,194	$ 4,843,468	$ 4,215,260	$ 3,817,380	$ 4,866,557	$ 4,040,707	$ 6,941,746	$ 7,059,421	$67,467,805
Imports	$ 4,757,627.35	$ 4,589,694.32	$ 3,462,923.76	$ 11,463,431.84	$ 11,169,882.87	$ 11,583,281.24	$ 8,099,729.47	$ 7,009,590.04	$ 10,846,749.33	$ 12,840,536.41	$ 6,018,108.42	$ 2,855,712.04	$94,697,267
Export Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)													$0
Total FAM related costs	**$ 102,748,495**	**$ 90,490,519**	**$ 87,588,134**	**$ 72,151,448**	**$ 64,916,645**	**$ 64,358,355**	**$ 71,674,875**	**$ 70,394,489**	**$ 63,997,384**	**$ 67,027,584**	**$ 76,406,263**	**$ 86,858,502**	**$ 918,612,694**
Total FAM related costs and Incremental Cost to OATT customers	**$ 103,820,358**	**$ 91,433,115**	**$ 88,369,434**	**$ 72,524,007**	**$ 65,080,112**	**$ 64,500,380**	**$ 71,937,924**	**$ 70,633,034**	**$ 64,205,413**	**$ 67,296,610**	**$ 76,962,628**	**$ 87,571,364**	**$ 924,334,379**
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	12,236,372	11,899,369	16,036,280	16,447,820	13,090,652	418,181	13,292,610	14,132,701	139,470,614
BLT Fuel Costs bfr BUTU													
GRLF													
1P - RTP													
ELIADC													
Shore Power													
EBS													
Export													
Total	$666,442	$572,516	$334,043	$672,296	$765,054	$981,238	$1,157,980	$1,506,607	$1,175,360	$872,849	$741,340	$827,467	$10,273,192
NRIS	**$3,389,237**	**$3,589,681**	**$4,112,442**	**$3,528,178**	**$3,229,511**	**$2,482,409**	**$2,309,965**	**$2,149,334**	**$3,273,229**	**$4,362,000**	**$6,574,920**	**$8,509,661**	**$47,510,568**
ERIS	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	**$33,418,031**
Total	**$5,998,897**	**$6,848,140**	**$7,739,532**	**$6,049,595**	**$6,080,001**	**$5,016,489**	**$4,501,921**	**$4,065,430**	**$5,524,047**	**$6,519,931**	**$10,286,836**	**$12,297,779**	**$80,928,599**
Usage Data													
kWh Requirements													
ATL Classes													
Domestic Total	707,116,004	662,646,274	625,765,329	481,109,226	389,926,477	315,832,492	344,330,438	345,113,243	297,672,902	353,637,738	468,685,690	652,943,045	5,644,778,858
Small General	43,075,431	40,044,871	39,161,684	30,230,565	27,720,465	25,609,499	28,480,010	27,980,457	24,810,312	26,296,289	31,350,205	37,550,416	382,310,202
General	244,403,273	222,662,284	231,108,747	183,668,663	171,134,295	175,321,259	191,978,244	189,967,402	172,653,292	184,720,285	205,040,721	220,852,532	2,393,510,995
Large General	31,382,222	29,891,458	30,891,848	29,105,540	29,221,607	30,362,399	36,118,000	34,951,453	33,036,649	31,616,065	30,196,319	29,813,722	376,587,283
Small Industrial	26,323,632	23,619,890	23,958,128	21,156,943	21,914,164	24,205,562	24,040,437	21,561,950	19,798,742	19,652,860	22,645,635	25,773,589	274,651,533
Medium Industrial	40,456,616	36,830,070	39,820,167	36,605,073	39,149,327	40,966,679	40,821,513	37,997,064	37,538,851	37,997,398	41,154,755	38,593,810	467,931,323
Large Industrial- FIRM	9,201,024	8,512,978	9,418,815	8,624,471	8,141,245	8,072,742	7,821,638	8,459,964	7,772,251	8,496,042	7,967,496	9,298,442	101,787,108
Large Industrial- INT	51,082,569	45,906,740	46,784,699	47,688,244	53,399,418	52,909,312	53,620,241	58,611,999	54,803,159	55,137,167	55,416,856	45,046,310	620,406,715
Large Industrial	60,283,593	54,419,718	56,203,514	56,312,715	61,540,663	60,982,054	61,441,880	67,071,964	62,575,410	63,633,209	63,384,353	54,344,751	722,193,823
PHP	54,993,729	48,380,250	74,923,076	71,657,003	71,917,020	65,921,139	77,532,680	71,777,511	77,257,186	83,278,469	74,585,898	57,772,243	829,996,205
Municipal	17,793,843	15,644,788	14,646,832	10,305,750	6,297,827	5,842,110	7,577,118	7,217,995	7,400,291	8,968,255	12,212,395	14,642,427	128,549,631

Category	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Annual
Unmetered	7,158,277	6,891,341	6,911,547	6,769,126	7,135,422	6,913,303	6,921,957	6,602,437	7,241,751	6,585,723	7,552,541	6,591,865	83,275,289
BTL													
BUTU	[redacted]												
GRLF													
1P - RTP													
ELIADC													
Shore Power													
EBS													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	2009 BUTU (NSPI-P-889)			2026 BUTU (NSPI-P-889) Updated for change in Interruptible Rider									
				Three Winter Season Average Coincident Factor									
Wnter Season	2008/2009			2017/2018			2018/2019			2019/2020			Average
Winter Month Peaks	Non-Coincident Demand	Coincident Demand	Co-incidence Factor	Non-Coincident Demand	Coincident Demand	Co-incidence Factor	Non-Coincident Demand	Coincident Demand	Co-incidence Factor	Non-Coincident Demand	Coincident Demand	Co-incidence Factor	
December													
January													
February													
Average			97.700%			99.800%			96.400%			96.400%	97.53%
Annual Levelized Capacity Cost as used for Int. Rider Purposes			$63.000										$160.435
Transmission Losses			3.0%										3.0%
Monthly Cost per kW			$5.410										$13.770
Monthly Charge ($/kW)			$5.286										$13.430

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's Renewable to Retail (RtR) Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities and is independent of the LRS' forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS' aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted

generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS' generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $414.63 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS' forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	**cents per kWh**
Fuel Cost	6.736
Fixed Cost Adder	2.166
Total	**8.902**

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

6.736 cents per kilowatt-hour.

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

Capacity adequacy service – fulfillment of the LRS' obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.

Top-up capacity service – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by Renewable to Retail (RtR) Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $414.63 per month.

DEMAND CHARGE

$5.452 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$\text{MSCD} = \text{LWPFD} - \textit{min}\ (\textit{LWPFD}, (\Sigma_{ii=1}^{nn}\ \textit{CCi} * \textit{GCi})/(1+\textit{PR}))$$

Where:

- "LWPFD" is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

  $$\text{LWPFD} = \Sigma_{i=1}^{k}(\textit{CMPFDi} * \textit{CMDAFi})$$

  Where:

  - "k" is the number of otherwise applicable bundled service rate classes to RtR customers of an LRS.
  - "CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research-based class load profile data.
  - "CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, Jun	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.34	2.13	2.26	1.65
Small General	1.00	1.24	1.62	1.59	1.35
General	1.00	1.21	1.47	1.36	1.20
Large General	1.00	0.99	0.93	0.86	0.99
Small Industrial	1.00	1.25	1.23	1.27	1.16
Medium Industrial	1.00	1.11	1.04	1.03	0.96
Large Industrial Firm	1.00	1.04	0.92	0.89	0.92
Unmetered	1.00	1.19	1.99	1.98	1.33

- "PR" is Planning Reserve (%) based on Northeast Power Coordinating Council planning criteria (i.e. 20% or as updated).

- "CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

- "GCi" is the generator capacity dedicated to serving LRS load.

- "n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff, or the Renewable to Retail Market Transition Tariff.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF **Page 1 of 2**
Renewable to Retail

PURPOSE

Pursuant to Section 3G(2) of the *Electricity Act* (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its Renewable to Retail (RtR) Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax, and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Energy Board (NSEB, Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

(1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, or the Energy Balancing Service Tariff. A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to greater than zero.

(2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

(3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

(4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS' supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

(5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

ENERGY CHARGE

The Energy Charge is made up of the following components:

Energy Charge Components	**cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	2.166
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	2.198
Total	**4.363**

The Energy Charge is applicable to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

The Demand Charge is made up of two components:

Demand Charge Components	**dollars per kW**
Demand Charge from Standby Service Tariff	$5.452
Annually Adjusted Demand Savings Credit	$0.000
Total	**$5.452**

The Demand Charge is applicable to the LRS' monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff, or the Energy Balancing Service Tariff.

2026 Energy Balancing Service

Annual Avoided Fuel Cost Calculations

Source		Annual MWh Load at Transmission Level	Generation non-fuel related costs			Avoided Unit Cost (c/kWh)
			Before Fixed Cost Deferral Adj.	Fixed Cost Deferral Adj. if applicable	After Fixed Cost Deferral Adj.	
	Spill Energy Credit rate					**6.736**
	Top-up Energy Rate Calculation					
	Fuel Cost charge					**6.736**
	Energy-related fixed cost Component					
2026 COSS - Exhibit 5; page 1 Energy - Exhibit 9A, line 11, col 3 divided by a transmission loss factor of 1.03.	Fixed Energy-related Cost in '000's of $	11,035,237	$238,981,773	$0	$238,981,773	**2.166**
	Charge in cents per kWh					
	Total top-up charge in cents per kWh					**8.902**

Top-up Energy Rate Calculation
Energy-related fixed cost Component
COST

Energy Expenses (Generation Function) from COSS Exh 5, cell E48	$980,912,547
FUEL	$434,032,951
PURCHASES - OTHER THAN BIOMASS AND WIND	$10,086,335
PURCHASES - BIOMASS	$14,873,936
MARITIME LINK	$109,425,900
PURCHASES - WIND ERIS	$18,243,420
PURCHASES - WIND NRIS	$60,877,434
IMPORTS	$94,390,798
BUTU CAPACITY CREDIT	$0
EXPORT SALES	$0
	$238,981,773
Annual GWh Load at Transmission Level	
Energy Requirement from COSS Exh 9a Annual, cell D24	11,303,785
Transmission Loss Factor 2026 COSS.	1.024
	11,035,237

STANDBY SERVICE TARIFF

Source	Category		
	Demand-related Costs	**Cost in thousands of $'s**	
2026 COSS - Exhibit 5, page 1, column 2.			$357,621.5
Less			
FUEL			$0
PURCHASES - OTHER THAN BIOMASS AND WIND			$8,334
PURCHASES - BIOMASS			$5,365
MARITIME LINK			$90,413
PURCHASES - WIND ERIS			$15,071
PURCHASES - WIND NRIS			$50,290
IMPORTS			$0
BUTU CAPACITY CREDIT			$302
Subtotal			$169,774
2026 COSS - Exhibit 5, page 1, column 2.	**Demand-related fixed gen costs net of fuel costs**		$187,847
	Less: Ancillary generation-related costs recovered under OATT		
	Reactive Supply & Voltage Control	$4,118	
	Regulation & Frequency	$5,099	
GRA 2026 DE-03 - DE-04 Appendix L Attachment 3 pages 7 and 8, Figures 3-7 and 3-8	Load Following	$21,166	
	Operating Reserve - Spinning (10 min)	$4,206	
	Operating Reserve - Supplemental (10 min)	$16,601	
	Operating Reserve - Supplemental (30 min)	$6,013	
		$57,203	
2026 COSS - Exhibit 6, page 6, column 1.	**Add: Interruptible Credit Cost**	$11,165	
	Demand-related fixed Gen. Costs net of Ancillary Service Costs3		$141,809

Capacity Usage in kW

Transmission Loss at 69 kV **4.22%**

		Sum of 3 Coincident Winter Peaks	3CP Monthly Ave	
		At Generator's Gate		**At 69 kV Transmission Voltage**
2026 COSS - Exhibit 9A, col 10.	(1) DOMESTIC	4,353,838	1,451,279	1,392,515
	(2) SMALL GENERAL	222,264	74,088	71,088
	(3) GENERAL	1,206,116	402,039	385,760
	(4) GENERAL LARGE	137,482	45,827	43,972
	(5) SMALL INDUSTRIAL	123,550	41,183	39,516
	(6) MEDIUM INDUSTRIAL	158,818	52,939	50,796
	(7) LARGE INDUSTRIAL	246,525	82,175	78,848
	(8) ELI 2P-RTP	203,227	67,742	64,999
	(9) MUNICIPAL	93,931	31,310	30,042
	(10) UNMETERED	31,520	10,507	10,081
		6,777,270	2,259,090	2,167,617
	TYPE OF SERVICE			
	FIRM	6,570,263	2,190,088	2,101,408
	INTERRUPTIBLE	207,007	69,002	66,208
	TOTAL	6,777,270	2,259,090	2,167,617

Standby Demand Charge Calculation

	Cost	Usage	Unit Annual Cost $/kW	Monthly Rate $/kW
Firm Service Cost	$141,809	2,167,617	$65.422	**$5.452**
Interruptible Service Credit	-$11,165	66,208	-$168.638	**-$14.053**

Renewable to Retail Market Transition Tariff - Annual Energy Cost Adjustment Calculations

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MWh Load at Transmission Level	9,795,528	9,824,765	9,848,989	9,869,561	9,832,403	9,835,173	9,702,219	9,737,166	9,806,153	9,806,153	11,038,853
Total Fuel Cost of FAM Rate Classes (before Fixed Cost Credits)	$490,811,695	$538,771,344	$574,677,297	$610,393,926	$589,397,630	$605,812,708	$626,447,003	$647,335,554	$753,854,785	$753,854,785	$864,917,556
Average Unit Cost at Transmssion Level (cents/kWh)	5.011	5.484	5.835	6.185	5.994	6.160	6.457	6.648	7.688	7.688	7.835
Average Marginal Fuel Cost from LF Rate (Cents/kWh)	4.239	4.668	5.647	6.275	6.200	6.134	7.292	11.042	8.322	8.919	6.736
Differential (Cents/kWh)	0.772	0.816	0.188	-0.0902	-0.206	0.026	-0.836	-4.394	-0.634	-1.231	1.099
Applicable Charge or Credit to dispalced energy on NS Power's generation system (Cents/kWh)	1.543	1.632	0.376	-0.180	-0.411	0.052	-1.671	-8.788	-1.268	-2.463	2.198

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

The Extra Large Industrial Active Demand Control Tariff (ELIADC) provides a mechanism whereby Port Hawkesbury Paper LP (PHP, the Mill, the Customer) pays the forecast incremental costs of its annual forecast service expressed as a levelized Customer Baseline Load (CBL) plus makes a contribution to utility costs, while providing Nova Scotia Power (NS Power) with control of PHP's load such that NS Power's overall system costs can be reduced and system reliability can be improved for the benefit of all NS Power customers.

AVAILABILITY

(a) This Tariff is applicable to operations at PHP's mill site at Point Tupper, and is premised upon PHP's electricity requirements being exclusively served by NS Power.

(b) In addition to the priority interruptible service load reduction requirements prescribed in this Tariff, PHP's load shall be further managed by NS Power in accordance with the Active Demand Control – Energy Supply Protocols attached as Schedule 1 to this Tariff.

(c) The service voltage shall not be less than 138 kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

(d) This Tariff cannot be taken in conjunction with other tariffs unless approved by the Nova Scotia Energy Board (NSEB, Board).

COST OF ELECTRICITY UNDER THE ELIADC TARIFF

The price paid by PHP for electricity under this Tariff will be based on the forecast incremental cost to serve PHP at an assumed levelized baseline load level, plus an adder to contribute to the reduction of the cost of service to other NS Power customers, less a credit to recognize system savings enabled by PHP's granting Active Demand Control of its load to NS Power. The credit is also intended to incent PHP to assist NS Power in realizing the full potential value of Active Demand Control by allowing PHP to share in the resulting system savings.

The pricing elements comprising the ELIADC are:

- Customer Baseline Energy Cost (CBL Cost)
- Customer Baseline Energy Charge (CBL Energy Charge)
- Customer Baseline Adder (CBLA)
- Variable Capital Charge
- Active Demand Control Credit

Minimum Payment

The ELIADC Tariff requires that a minimum payment shall be made by PHP in respect of each tariff year, which shall not be less than the sum of:

(a) NS Power's actual total incremental cost of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power's incremental generation and delivery of electricity to the customer), plus

(b) $5.00 multiplied by the total number of MWh supplied in the year (i.e. the minimum Fixed Cost Recovery, FCR).

Any adjustments required to achieve this minimum payment amount will be determined and charged to PHP after year end.

Customer Baseline Energy Charge, Customer Baseline Energy Cost, and Contribution to Utility Costs

In advance of each tariff year, PHP shall advise NS Power of its forecast annual and monthly energy requirements for the subsequent calendar year, including the anticipated dates and durations of PHP's major scheduled maintenance periods. Upon receipt of such forecast, NS Power will then calculate, in $/MWh, its forecast annual cost to serve PHP at a levelized baseline load level (i.e., the Customer's average demand will be assumed to be the same in each hour after taking into account major scheduled maintenance) to produce the CBL Cost.

The CBL Cost calculation will be inclusive of all incremental, non-capital costs to serve PHP and will assume no economic load shifting (e.g. no reductions in usage in high-cost hours or increased usage in low-cost hours). The CBL Cost will include the forecast cost of fuel and purchased power, line losses, and variable operating costs for NS Power's incremental generation and delivery of electricity to PHP and FCR, which is transferred to the CBL Adder (CBLA), as described in the bulleted list below, to produce the CBL Energy Charge. The CBL Energy Charge will form the basis of the ELIADC Energy Charge for the upcoming calendar year.

A CBL Adder will be calculated with reference to the forecast CBL Cost. As the forecast CBL Cost ($/MWh) decreases, the CBLA increases.

- When the forecast CBL Cost is at or under $56.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL Cost and $61.75/MWh. As the CBLA is equal to or more than the $5/MWh FCR, the FCR is fully included in the CBLA.
- When the forecast CBL Cost is more than $56.75/MWh and under $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is the differential between the $5/MWh FCR and the calculated CBLA of 75 percent of the difference between the forecast CBL Cost and

$61.75/MWh. The FCR transferred from the CBL Cost is then added to the calculated CBLA to equal $5/MWh FCR.

- When the forecast CBL Cost is at or over $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is $3.75/MWh. The difference between the forecast CBL Cost and $61.75/MWh is assigned a value of zero, and the CBLA is calculated as $5/MWh FCR.

The CBL Energy Charge is equal to the CBL Cost less the FCR transferred to the CBLA. The CBL Energy Charge and the associated CBLA shall be submitted for Board approval on an annual basis as part of the annual proceeding by which NS Power's Annually Adjusted Rates are established.

In addition to the CBL Energy Charge and CBLA, PHP will pay a Variable Capital Charge (VCC) for NS Power's incremental generation and delivery of electricity to PHP in the amount of $1.02/MWh.

In summary, the Tariff energy charge per MWh will be calculated as follows:

$$\textit{ELIADC Energy Charge} = \textit{CBL Energy Charge} + \textit{CBLA} + \textit{VCC}$$

ELIADC ENERGY CHARGE

The ELIADC Energy Charge is $75.87 per Megawatt- hour

INTRA-YEAR MODIFICATIONS TO THE CBL ENERGY CHARGE

NS Power will utilize its established forecasting methodology to determine the CBL Energy Charge. PHP will undertake commercially reasonable efforts to accurately forecast its energy usage.

If, during any year, certain circumstances, such as those described in the next paragraphs, change significantly resulting in a material impact on the appropriate CBL Energy Charge to be paid by PHP during the year, NS Power may, upon approval of the Board, revise the CBL Energy Charge on a prospective basis.

In recognition that the calculation of the CBL Energy Charge for 2020 may be materially impacted if there are delays to the start date of deliveries of the NS Block energy import beyond June 1, 2020, if NS Power determines that any such delay will have a material impact on the appropriate CBL Energy Charge to be paid by PHP for 2020, then the CBL Energy Charge will be subject to recalculation pursuant to this provision.

Additional circumstances which, if changed significantly, would warrant reassessment of the CBL Energy Charge could include, but are not limited to:

(a) It becomes apparent that the CBL Energy Charge plus the CBLA plus the Variable Capital Charge will not result in the recovery of the actual incremental cost to serve plus $5/MWh FCR;

(b) Material and unexpected change in the cost of generation as compared to the CBL Energy Charge calculation;

(c) Material and unexpected increased electricity consumption by PHP during the year, such as significant physical plant modification (as signified by a specific capital expenditure beyond normal annual capital spending), a change in product line or a material non-forecast change in product demand; and

(d) Material and unexpected decrease in electricity consumption by PHP during the year (such as due to plant shutdowns, labour issues, or market downtime).

If PHP and NS Power are unable to agree on the required changes to the CBL Energy Charge as a result of any of the above modifications, the matter may be submitted to the Board by either party on an expedited basis for adjudication. Revisions to the CBL Energy Charge will not change the Minimum Payment to be made by PHP.

ACTIVE DEMAND CONTROL AND SCHEDULE VARIANCE

NS Power shall be entitled to actively manage PHP's load in accordance with the terms and conditions set out in the Active Demand Control – Energy Supply Protocol attached as Schedule 1 to this Tariff.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, taking account of the impacts of any variances by PHP from the dispatch schedules issued to it by NS Power and any adjustments arising from schedule variances if required. In accordance with the Board's direction in NS Power's Application for a Third Term of the ELIADC Tariff (M12184), the Company's annual reporting will further include "more detailed quantification of actual load shifting benefits (and costs), an identification and discussion of the types of deviations that provide the most benefits and why, ways to improve the tariff or tariff administration, and a comparison of current year outcomes to prior years to help to evaluate ELIADC performance over time."[1] NS Power shall endeavor to submit this report no later than 60 days after the end of a tariff year.

PHP will be entitled to a credit equal to 25 percent of the cost differential between the CBL Cost and the actual annual cost to serve PHP during the given tariff year. Such payments to the Customer will be made via an annual lump sum payment.

[1] M12184 – NSEB Decision, 324430, page 5. September 22, 2025.

TERM

The third term of this Tariff is 2026, unless revised per a Decision of the NSEB (Term). Prior to the end of the third term, NS Power or PHP may apply to the Board for approval of a subsequent term for this Tariff, including the approval of the pricing elements of the Tariff to be applied during the subsequent term or PHP's transition to an alternative tariff.

REOPENER

If, at any time during the Term, NS Power or PHP determines that the ELIADC Tariff is not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the Tariff, or the components thereof, on a prospective basis. If necessary, and to protect customers, the Board may grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the Tariff.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings.

FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue that can directly impact on NS Power's incremental electricity costs.

MINIMUM LOAD REQUIREMENT

NS Power will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25,000 kVA.

INTERRUPTIBILITY

The Mill will reduce its load by, at a minimum, the amount requested by NS Power within 10 minutes of such request by NS Power. Following such interruption, service may only be restored by the Mill with the approval of NS Power.

PHP will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes.

Load interruption calls will be made to PHP in advance of all such calls to NS Power's Large Industrial Interruptible Rider customers. Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by NS Power, NS Power may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NS Power will exercise the automated control of the customer's load to interrupt the customer load.

PHP is expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable formula cost for energy taken under this Tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the formula amount, effective at that time for the consumption used in that month.

Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should PHP desire to be served under any applicable firm service tariff, a five-year advance written notice must be given to NS Power so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service

received by NS Power. NS Power may, however, permit an earlier conversion. If PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two years of service under the firm tariff schedule. NS Power may permit an earlier conversion from firm to interruptible service.

Order of Interruptibility

In the event an interruption call is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NS Power in the following order:

(1) Generation Replacement and Load Following (GRLF) Tariff;

(2) Extra Large Industrial Active Demand Control Tariff;

(3) Shore Power Tariff;

(4) Interruptible Rider to the Large Industrial Tariff.

In situations in which load of the customer under this Tariff is held as Operating Reserve, NS Power may change the above order of interruption by interrupting Large Industrial Interruptible Rider Tariff customers whose load is not held as Operating Reserve before interrupting the Customer.

MAINTAIN SYSTEM INTEGRITY

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SECURITY FOR PAYMENTS

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days. As security for payment, PHP shall provide NS Power a letter of credit from time to time. The form, amount, and issuer of the letter of credit will be satisfactory to NS Power. To the extent that a letter of credit introduces a lag time and there are additional costs to NS Power, these will be paid by PHP not NS Power or its customers.

SEPARATE SERVICE AGREEMENT

NS Power reserves the right to have a separate service agreement if, in the opinion of NS Power, issues not specifically set out herein must be addressed for the ongoing benefit of NS Power and its customers.

POWER FACTOR CORRECTION

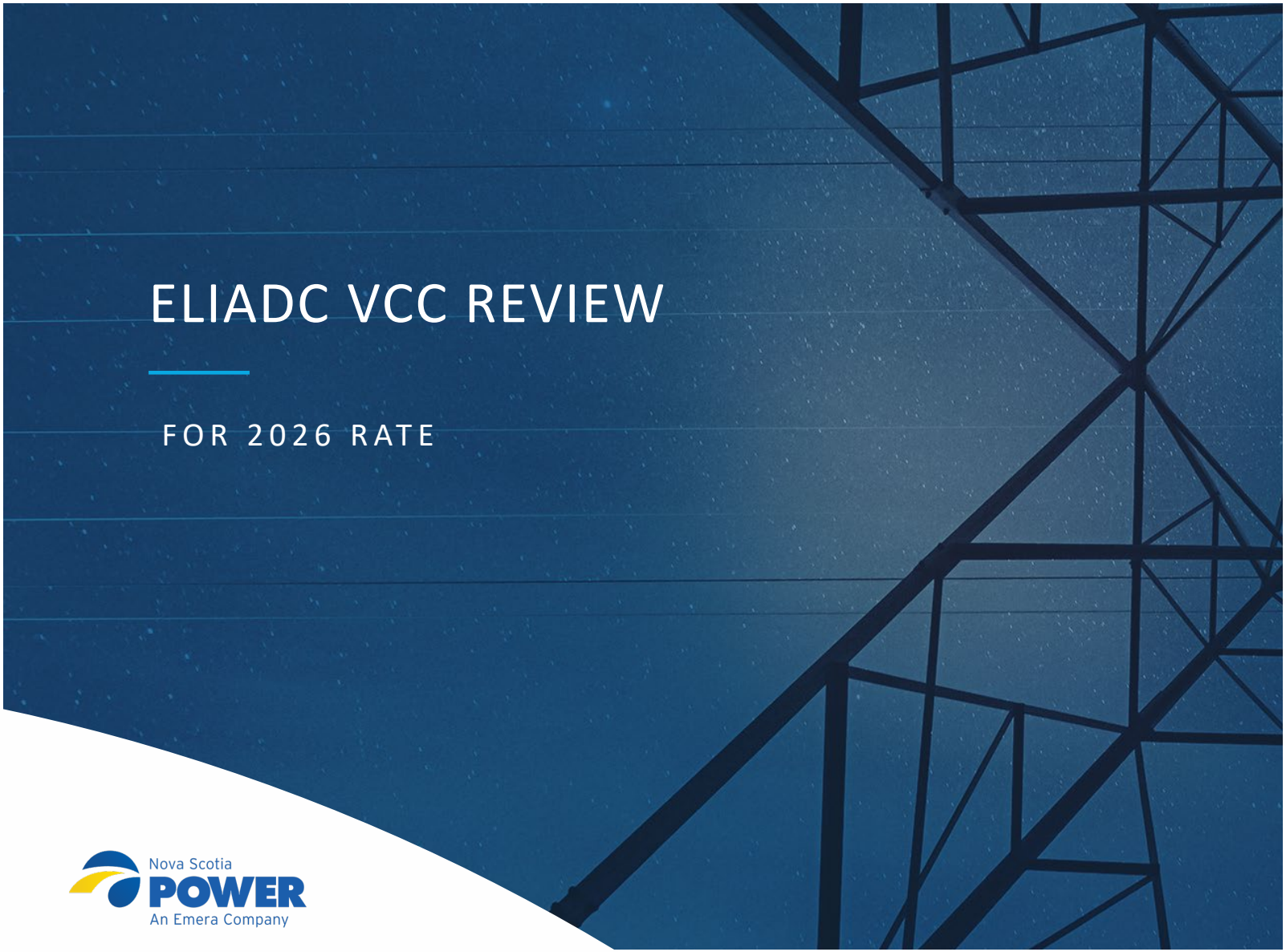
Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the CBL Energy Charge:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

METERING COSTS

Metering will normally be at the low voltage side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.1%. Should the Mill's requirements make it necessary for NS Power to provide primary metering, PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this Tariff shall be paid for by PHP as a capital contribution.

2026 Annually Adjusted Rates Confidential Appendix G2 has been removed due to confidentiality.


ELIADC VCC REVIEW
FOR 2026 RATE
Nova Scotia
POWER
An Emera Company

OVERVIEW

NS Power has reviewed the VCC for 2026. Based on the resulting model projections, PHP is forecast to use higher levels of NS Power's assets to support its load as compared to the ELIADC Tariff model in 2025.

In undertaking its review and modeling, NS Power applied the methodology outlined in paragraphs 53 and 54 of the Board's Decision approving the ELIADC Tariff.* This presentation summarizes the forecast changes in utilization with and without PHP on the system in 2026.

The VCC should be updated to reflect these changes in forecast utilization. The proposed revised VCC is $1.02/MWh for 2026. Going forward NS Power proposes to re-calculate and update the VCC annually.

*M09420, Board Decision, paragraphs 53-54, March 26. 2020.

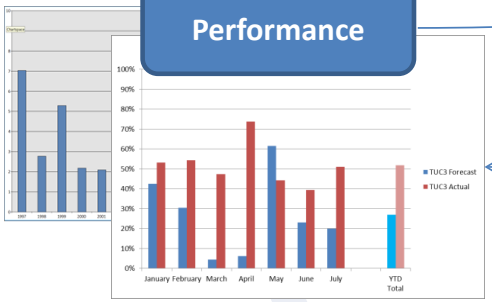
PLAN

Resource Planning

Inputs
- O&M
- DAFOR
- Unit Capability
- System Demand
- Fuel Prices
- Cycling

ANALYZE

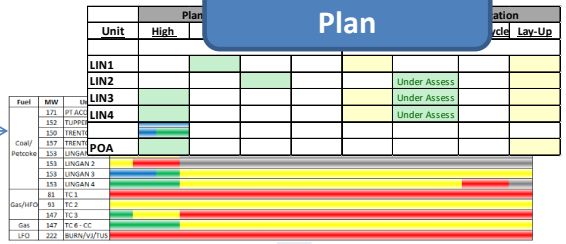
Performance



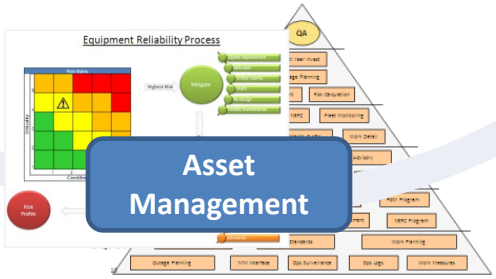
Update inputs

Reconciliation

Unit Utilization Plan



PROJECT



Asset Management

OPERATE

Unit Utilization – Utilization Factor

- Traditionally capacity factor was used to estimate future demand on units
- Given increasing renewables and required flexibility, necessary to also consider the effects of unit starts, operating hours, and unit health



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Unit Utilization – Utilization Factor Criteria

UF	Cost Factor	Unit Starts	Op Hours	CF
H	1.00	>50	>5000	>75
M	0.75	21-50	2500-5000	50-75
L	0.50	0-20	1000-2500	25-50
UL	0.25		0-1000	<25

VCC: UNIT UTILIZATION OVERVIEW

	No PHP Load				With PHP Load				Delta	
Unit	CF (%)	Hours/yr	Starts/yr	UF	CF (%)	Hours/yr	Starts/yr	UF	UF Delta	Sustaining Capital Delta
01 - Lingan 1	[redacted]									
02 - Lingan 2										
03 - Lingan 3										
04 - Lingan 4										
05 - Point Aconi										
06 - Point Tupper										
07 - Trenton 5										
08 - Trenton 6										
09 - PHBM										
11 - Tufts Cove 1										
12 - Tufts Cove 2										
13 - Tufts Cove 3										
14 - Tufts Cove 4										
15 - Tufts Cove 5										
16 - Tufts Cove 6										
Total										$787,508

VCC CALCULATION

Description	Units	Value
Variable capital cost impact	$	$787,508
PHP load forecast-2026	GWh	774.46
VCC Rate	$/MWh	$1.02

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF **Page 1 of 8**

The Extra Large Industrial Active Demand Control Tariff (ELIADC) provides a mechanism whereby Port Hawkesbury Paper LP (PHP, the Mill, the Customer) pays the forecast incremental costs of its annual forecast service expressed as a levelized Customer Baseline Load (CBL) plus makes a contribution to utility costs, while providing Nova Scotia Power (NS Power) with control of PHP's load such that NS Power's overall system costs can be reduced and system reliability can be improved for the benefit of all NS Power customers.

AVAILABILITY

(a) This Tariff is applicable to operations at PHP's mill site at Point Tupper, and is premised upon PHP's electricity requirements being exclusively served by NS Power.

(b) In addition to the priority interruptible service load reduction requirements prescribed in this Tariff, PHP's load shall be further managed by NS Power in accordance with the Active Demand Control – Energy Supply Protocols attached as Schedule 1 to this Tariff.

(c) The service voltage shall not be less than 138 kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

(d) This Tariff cannot be taken in conjunction with other tariffs unless approved by the Nova Scotia Energy Board (NSEB, Board).

COST OF ELECTRICITY UNDER THE ELIADC TARIFF

The price paid by PHP for electricity under this Tariff will be based on the forecast incremental cost to serve PHP at an assumed levelized baseline load level, plus an adder to contribute to the reduction of the cost of service to other NS Power customers, less a credit to recognize system savings enabled by PHP's granting Active Demand Control of its load to NS Power. The credit is also intended to incent PHP to assist NS Power in realizing the full potential value of Active Demand Control by allowing PHP to share in the resulting system savings.

The pricing elements comprising the ELIADC are:

- Customer Baseline Energy Cost (CBL Cost)
- Customer Baseline Energy Charge (CBL Energy Charge)
- Customer Baseline Adder (CBLA)
- Variable Capital Charge
- Active Demand Control Credit

Minimum Payment

The ELIADC Tariff requires that a minimum payment shall be made by PHP in respect of each tariff year, which shall not be less than the sum of:

(a) NS Power's actual total incremental cost of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power's incremental generation and delivery of electricity to the customer), plus

(b) $5.00 multiplied by the total number of MWh supplied in the year (i.e. the minimum Fixed Cost Recovery, FCR).

Any adjustments required to achieve this minimum payment amount will be determined and charged to PHP after year end.

Customer Baseline Energy Charge, Customer Baseline Energy Cost, and Contribution to Utility Costs

In advance of each tariff year, PHP shall advise NS Power of its forecast annual and monthly energy requirements for the subsequent calendar year, including the anticipated dates and durations of PHP's major scheduled maintenance periods. Upon receipt of such forecast, NS Power will then calculate, in $/MWh, its forecast annual cost to serve PHP at a levelized baseline load level (i.e., the Customer's average demand will be assumed to be the same in each hour after taking into account major scheduled maintenance) to produce the CBL Cost.

The CBL Cost calculation will be inclusive of all incremental, non-capital costs to serve PHP and will assume no economic load shifting (e.g. no reductions in usage in high-cost hours or increased usage in low-cost hours). The CBL Cost will include the forecast cost of fuel and purchased power, line losses, and variable operating costs for NS Power's incremental generation and delivery of electricity to PHP and FCR, which is transferred to the CBL Adder (CBLA), as described in the bulleted list below, to produce the CBL Energy Charge. The CBL Energy Charge will form the basis of the ELIADC Energy Charge for the upcoming calendar year.

A CBL Adder will be calculated with reference to the forecast CBL Cost. As the forecast CBL Cost ($/MWh) decreases, the CBLA increases.

- When the forecast CBL Cost is at or under $56.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL Cost and $61.75/MWh. As the CBLA is equal to or more than the $5/MWh FCR, the FCR is fully included in the CBLA.
- When the forecast CBL Cost is more than $56.75/MWh and under $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is the differential between the $5/MWh FCR and the calculated CBLA of 75 percent of the difference between the forecast CBL Cost and

$61.75/MWh. The FCR transferred from the CBL Cost is then added to the calculated CBLA to equal $5/MWh FCR.

- When the forecast CBL Cost is at or over $61.75/MWh, the FCR to be transferred from the forecast CBL Cost is $3.75/MWh. The difference between the forecast CBL Cost and $61.75/MWh is assigned a value of zero, and the CBLA is calculated as $5/MWh FCR.

The CBL Energy Charge is equal to the CBL Cost less the FCR transferred to the CBLA. The CBL Energy Charge and the associated CBLA shall be submitted for Board approval on an annual basis as part of the annual proceeding by which NS Power's Annually Adjusted Rates are established.

In addition to the CBL Energy Charge and CBLA, PHP will pay a Variable Capital Charge (VCC) for NS Power's incremental generation and delivery of electricity to PHP in the amount of $~~3.34~~1.02/MWh.

In summary, the Tariff energy charge per MWh will be calculated as follows:

ELIADC Energy Charge = CBL Energy Charge + CBLA + VCC

ELIADC ENERGY CHARGE

~~Information on the CBL Energy Charge and VCC for 2026 will be provided to the Board by November 7, 2025.~~The ELIADC Energy Charge is $75.87 per Megawatt- hour

INTRA-YEAR MODIFICATIONS TO THE CBL ENERGY CHARGE

NS Power will utilize its established forecasting methodology to determine the CBL Energy Charge. PHP will undertake commercially reasonable efforts to accurately forecast its energy usage.

If, during any year, certain circumstances, such as those described in the next paragraphs, change significantly resulting in a material impact on the appropriate CBL Energy Charge to be paid by PHP during the year, NS Power may, upon approval of the Board, revise the CBL Energy Charge on a prospective basis.

In recognition that the calculation of the CBL Energy Charge for 2020 may be materially impacted if there are delays to the start date of deliveries of the NS Block energy import beyond June 1, 2020, if NS Power determines that any such delay will have a material impact on the appropriate CBL Energy Charge to be paid by PHP for 2020, then the CBL Energy Charge will be subject to recalculation pursuant to this provision.

Additional circumstances which, if changed significantly, would warrant reassessment of the CBL Energy Charge could include, but are not limited to:

(a) It becomes apparent that the CBL Energy Charge plus the CBLA plus the Variable Capital Charge will not result in the recovery of the actual incremental cost to serve plus $5/MWh FCR;

(b) Material and unexpected change in the cost of generation as compared to the CBL Energy Charge calculation;

(c) Material and unexpected increased electricity consumption by PHP during the year, such as significant physical plant modification (as signified by a specific capital expenditure beyond normal annual capital spending), a change in product line or a material non-forecast change in product demand; and

(d) Material and unexpected decrease in electricity consumption by PHP during the year (such as due to plant shutdowns, labour issues, or market downtime).

If PHP and NS Power are unable to agree on the required changes to the CBL Energy Charge as a result of any of the above modifications, the matter may be submitted to the Board by either party on an expedited basis for adjudication. Revisions to the CBL Energy Charge will not change the Minimum Payment to be made by PHP.

ACTIVE DEMAND CONTROL AND SCHEDULE VARIANCE

NS Power shall be entitled to actively manage PHP's load in accordance with the terms and conditions set out in the Active Demand Control – Energy Supply Protocol attached as Schedule 1 to this Tariff.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, taking account of the impacts of any variances by PHP from the dispatch schedules issued to it by NS Power and any adjustments arising from schedule variances if required. In accordance with the Board's direction in NS Power's Application for a Third Term of the ELIADC Tariff (M12184), the Company's annual reporting will further include "more detailed quantification of actual load shifting benefits (and costs), an identification and discussion of the types of deviations that provide the most benefits and why, ways to improve the tariff or tariff administration, and a comparison of current year outcomes to prior years to help to evaluate ELIADC performance over time."[1] NS Power shall endeavor to submit this report no later than 60 days after the end of a tariff year.

PHP will be entitled to a credit equal to 25 percent of the cost differential between the CBL Cost and the actual annual cost to serve PHP during the given tariff year. Such payments to the Customer will be made via an annual lump sum payment.

[1] M12184 – NSEB Decision, 324430, page 5. September 22, 2025.

TERM

The third term of this Tariff is 2026, unless revised per a Decision of the NSEB (Term). Prior to the end of the third term, NS Power or PHP may apply to the Board for approval of a subsequent term for this Tariff, including the approval of the pricing elements of the Tariff to be applied during the subsequent term or PHP's transition to an alternative tariff.

REOPENER

If, at any time during the Term, NS Power or PHP determines that the ELIADC Tariff is not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the Tariff, or the components thereof, on a prospective basis. If necessary, and to protect customers, the Board may grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the Tariff.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings.

FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue that can directly impact on NS Power's incremental electricity costs.

MINIMUM LOAD REQUIREMENT

NS Power will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25,000 kVA.

INTERRUPTIBILITY

The Mill will reduce its load by, at a minimum, the amount requested by NS Power within 10 minutes of such request by NS Power. Following such interruption, service may only be restored by the Mill with the approval of NS Power.

PHP will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes.

Load interruption calls will be made to PHP in advance of all such calls to NS Power's Large Industrial Interruptible Rider customers. Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by NS Power, NS Power may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NS Power will exercise the automated control of the customer's load to interrupt the customer load.

PHP is expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable formula cost for energy taken under this Tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the formula amount, effective at that time for the consumption used in that month.

Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should PHP desire to be served under any applicable firm service tariff, a five-year advance written notice must be given to NS Power so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service

received by NS Power. NS Power may, however, permit an earlier conversion. If PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two years of service under the firm tariff schedule. NS Power may permit an earlier conversion from firm to interruptible service.

Order of Interruptibility

In the event an interruption call is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NS Power in the following order:

(1) Generation Replacement and Load Following (GRLF) Tariff;

(2) Extra Large Industrial Active Demand Control Tariff;

(3) Shore Power Tariff;

(4) Interruptible Rider to the Large Industrial Tariff.

In situations in which load of the customer under this Tariff is held as Operating Reserve, NS Power may change the above order of interruption by interrupting Large Industrial Interruptible Rider Tariff customers whose load is not held as Operating Reserve before interrupting the Customer.

MAINTAIN SYSTEM INTEGRITY

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SECURITY FOR PAYMENTS

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days. As security for payment, PHP shall provide NS Power a letter of credit from time to time. The form, amount, and issuer of the letter of credit will be satisfactory to NS Power. To the extent that a letter of credit introduces a lag time and there are additional costs to NS Power, these will be paid by PHP not NS Power or its customers.

SEPARATE SERVICE AGREEMENT

NS Power reserves the right to have a separate service agreement if, in the opinion of NS Power, issues not specifically set out herein must be addressed for the ongoing benefit of NS Power and its customers.

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF **Page 8 of 8**

POWER FACTOR CORRECTION

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the CBL Energy Charge:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

METERING COSTS

Metering will normally be at the low voltage side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.1%. Should the Mill's requirements make it necessary for NS Power to provide primary metering, PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this Tariff shall be paid for by PHP as a capital contribution.

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's Renewable to Retail (RtR) Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities and is independent of the LRS' forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS' aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted

generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS' generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $~~401.58~~414.63 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS' forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	**cents per kWh**
Fuel Cost	~~8.919~~6.736
Fixed Cost Adder	~~3.264~~2.166
Total	~~**12.183**~~**8.902**

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

~~8.919~~6.736 cents per kilowatt-hour.

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia ~~Utility and Review~~Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

GENERATION REPLACEMENT AND LOAD FOLLOWING TARIFF **Page 1 of 5**

SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

Generation Replacement Service – backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

Optional Load Following Service – energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

Spill Service – hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators."

Rate

Backup Service

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be ~~9.419~~7.236 cents per kWh.

ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition 8, normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(4) Following interruption, service may only be restored by the customer with approval of the Company.

(5) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(6) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia ~~Utility and Review~~ Energy Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected customer shall be notified.

ONE PART DISTRIBUTION VOLTAGE REAL TIME PRICING TARIFF **Page 1 of 3**

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): ~~8.903~~ 10.008 ¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): ~~2.580~~ 3.573 ¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia ~~Utility and Review~~Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 kV and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer

will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF **Page 1 of 2**
Renewable to Retail

PURPOSE

Pursuant to Section 3G(2) of the *Electricity Act* (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its Renewable to Retail (RtR) Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax, and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia ~~Utility and Review~~Energy Board (NSEB, Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

(1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, or the Energy Balancing Service Tariff. A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to greater than zero.

(2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

(3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

(4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS' supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

(5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

ENERGY CHARGE

The Energy Charge is made up of the following components:

Energy Charge Components	**cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	~~3.264~~2.166
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	~~(2.463)~~2.198
Total	**~~0.802~~4.363**

The Energy Charge is applicable to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

The Demand Charge is made up of two components:

Demand Charge Components	**dollars per kW**
Demand Charge from Standby Service Tariff	$~~3.397~~5.452
Annually Adjusted Demand Savings Credit	$0.000
Total	**$~~3.397~~5.452**

The Demand Charge is applicable to the LRS' monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia ~~Utility and Review~~Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff, or the Energy Balancing Service Tariff.

SHORE POWER TARIFF **Page 1 of 4**

AVAILABILITY

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate;
(ii.) ~~Load Retention Tariff~~Extra Large Industrial Active Demand Control Tariff and PHP Tariff;
(iii.) Shore Power Tariff; and
(iv.) Interruptible Rider to the Large Industrial Rate.

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

ENERGY CHARGE

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

Base Energy Charge Components	**~~Transmission Voltage of 138 kV or Higher (cents per kWh)~~**	**Transmission Voltage of 69 kV or Higher (cents per kWh)**	**Distribution Voltage (cents per kWh)**
Fuel Cost	~~9.187~~6.900	6.900~~9.276~~	~~9.464~~7.062
Fixed Cost Adder	~~3.919~~2.516	2.516~~4.130~~	~~5.461~~4.064
Total	**~~13.106~~9.417**	9.417**~~13.406~~**	**~~14.926~~11.126**

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

SUPPLY INTERRUPTIONS

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non- compliance took place.

Penalty for Non-Compliance

All energy served after the 10-minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2,000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

SPECIAL CONDITIONS

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection, and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two-year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

Capacity adequacy service – fulfillment of the LRS' obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.

Top-up capacity service – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by Renewable to Retail (RtR) Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $~~401.58~~414.63 per month.

DEMAND CHARGE

$~~3.397~~5.452 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$\text{MSCD} = \text{LWPFD} - min\ (LWPFD, (\Sigma_{ii=1}^{nn}\ CCi * GCi)/(1+PR))$$

Where:

- "LWPFD" is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

  $$\text{LWPFD} = \Sigma_{i=1}^{k}(CMPFDi * CMDAFi)$$

  Where:

  - "k" is the number of otherwise applicable bundled service rate classes to RtR customers of an LRS.
  - "CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research-based class load profile data.
  - "CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, Jun	Jul, Aug, Sep	Oct, Nov
Domestic	1.00~~1.00~~	1.34 ~~1.27~~	2.13 ~~1.67~~	2.26 ~~2.17~~	1.65 ~~1.47~~
Small General	1.00~~1.00~~	1.24 ~~1.21~~	1.62 ~~1.32~~	1.59 ~~1.09~~	1.35 ~~1.28~~
General	1.00~~1.00~~	1.21 ~~1.12~~	1.47 ~~1.32~~	1.36 ~~1.05~~	1.20 ~~1.19~~
Large General	1.00~~1.00~~	0.99 ~~1.05~~	0.93 ~~1.04~~	0.86 ~~0.78~~	0.99 ~~0.99~~
Small Industrial	1.00~~1.00~~	1.25 ~~1.06~~	1.23 ~~1.01~~	1.27 ~~0.94~~	1.16 ~~1.00~~
Medium Industrial	1.00~~1.00~~	1.11 ~~1.14~~	1.04 ~~1.08~~	1.03 ~~1.01~~	0.96 ~~1.02~~
Large Industrial Firm	1.00~~1.00~~	1.04 ~~1.10~~	0.92 ~~1.03~~	0.89 ~~0.89~~	0.92 ~~1.09~~
Unmetered	1.00~~1.00~~	1.19 ~~8.24~~	1.99 ~~7.90~~	1.98 ~~7.68~~	1.33 ~~2.28~~

- "PR" is Planning Reserve (%) based on Northeast Power Coordinating Council planning criteria (i.e. 20% or as updated).

- "CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

- "GCi" is the generator capacity dedicated to serving LRS load.

- "n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia ~~Utility and Review~~Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff, or the Renewable to Retail Market Transition Tariff.

CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $~~401.58~~414.63 per month.

DEMAND CHARGE

The demand charge for this service is made up of the following two components:

(1) Annually adjusted demand-related purchased power cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism, or General Rate Application.

(2) Demand-related fixed generation cost, coming into effect as a result of a General Rate Application.

Demand Charge Components	**$ per kW of billing demand**
Demand-related Purchased Power Cost	$~~4.368~~6.252
Demand-related Fixed Generation Cost	$~~2.792~~5.452
Total	**$~~7.160~~11.704**

Contract Demand requirement is defined as the firm demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third-party supplier.

Billing demand is determined based upon the following formula:

$$\text{Billing demand} = (PR/(1+PR) * \min(CD, CCF * GC)) + (CD - \min(CD, CCF*GC))$$

Where:

PR is Planning Reserve (based on NPCC planning criteria, i.e. 20% or as updated)

GC is the third-party supplier's generating capacity

(a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.

(b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand.

CD is the customer's Contract Demand

CCF is the capacity contribution factor of the third party supplier's generation to the NSPI system, as determined at the beginning of a billing year by NSPI using information provided in accordance with Special Condition 7 of this tariff and in a manner consistent with NSPI's generation planning studies as amended from time to time.

ENERGY CHARGE

The energy charge is made up of the following two components:

(1) Annually adjusted energy-related purchased power and fuel cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism or General Rate Application.

(2) Energy-related fixed generation cost, coming into effect as a result of a General Rate Application.

Energy Charge Components	**cents per kWh**
Energy-related Purchased Power and Fuel Cost	~~7.926~~6.984
Energy-related Fixed Generation Cost	~~2.651~~2.166
Total	**~~10.577~~9.150**

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(d) of the *Electricity Act*, Chapter 25 of the Acts of 2004.

(d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

The tariff is applicable to the *scheduled* backup/top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

(a) The Municipal utility or utilities for which service is being requested.

(b) The year for which service is being requested.

(c) The contract demand (kW) required for backup and top-up service.

(d) The portion of the customer's annual load contracted to be supplied by third-party suppliers or through self-supply.

(e) The names, addresses, contact details and supply arrangements associated with contracted third-party suppliers.

(2) Backup/top-up service will be subscribed on a minimum 12 month, annual-renewable basis, provided that, if a wholesale customer satisfies the requirement of Special Condition 7(d), the backup/top-up service required with respect to the wholesale customer's procured capacity which satisfies the requirement of Special Condition 7(d) shall be subscribed by the customer on a minimum three-year forward basis.

Applications for service with a CCF value greater than zero in the billing demand calculation of the demand charge must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision by March 31st of each year following an application.

Applications for service with a CCF value of zero in the billing demand calculation of the demand charge must be provided to NSPI by no later than September 1st, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision within two months of receipt of such an application.

(3) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.1% for each transformation between the meter and the transmission voltage.

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under the Open Access Transmission Tariff (OATT).

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(7) Unless the following can be demonstrated by the wholesale customer to the satisfaction of NSPI, the CCF shall be attributed a value of zero in the billing demand calculation of the demand charge:

(a) For a third-party generation resource within Nova Scotia (Internal Resource):

(i.) If the Internal Resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the wholesale customer to NSPI, if directed to do so by the Nova Scotia Power System Operator (NSPSO), in the event of a resource adequacy need;

(ii.) If the Internal Resource is non-dispatchable, that it make its full output contracted to, but unused by, the wholesale customer available to deliver energy to NSPI, in the event of a resource adequacy need;

(iii.) The Internal Resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO; and

(iv.) Any export transactions utilizing energy from the Internal Resource will be recallable by the NSPSO, up to the amount contracted to the wholesale customer, for delivery to the NSPI system in the event of a resource adequacy need.

(b) For a third-party generation resource outside of Nova Scotia (External Resource):

(i.) The energy from the External Resource that is contracted to the wholesale customer will be scheduled and delivered to NSPI in the event of a resource adequacy need;

(ii.) The capacity from the External Resource that is contracted to the wholesale customer must be associated with one or more specific external resource assets, or be system-backed import capacity supported by the external control area where the capacity will be afforded the same curtailment priority as the external control area's native load, and be available to the NSPSO in the event of a resource adequacy need;

(iii.) If the capacity from the External Resource that is contracted to the wholesale customer is associated with one or more specific external resource assets, the wholesale customer must provide:

1. The name and location of each external resource asset;
2. For each asset, generator data including documentation of dependable maximum net capacity and NERC Generating Availability Data System data;
3. Documentation demonstrating proof of contractual control of the capacity all the way to each external resource asset providing the capacity; and
4. Letter of attestation or other documentation from the External Resource owner establishing that the capacity from the External Resource is not being used as capacity in any other balancing area.

(iv.) If the capacity from the External Resource will be supported by the external control area, the wholesale customer must provide:

1. Documentation demonstrating that the import capacity will be supported by the external control area and afforded the same curtailment priority as the external control area's native load.
2. Documentation demonstrating that the External Resource has firm transmission from the specific external resource asset or external control area to the NSPI system.

(c) The Internal Resource or External Resource, as applicable, will perform as needed to meet NSPI's reliability requirements.

(d) The capacity derived based on the CCF is procured and available to the wholesale customer on a minimum three-year forward basis, unless this requirement is waived by NSPI.

(8) In the event of a failure by the Internal Resource or External Resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO in accordance with Special Condition 7, above, then the wholesale customer will be required to make payment to NSPI of an amount equal to the costs incurred by NSPI to procure or to self-supply the undelivered energy and/or capacity, as applicable, less the energy charge paid by the wholesale customer to NSPI under this tariff with respect to any such undelivered energy and/or capacity, as applicable. If delivery of an Internal Resource or External Resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NSPI pursuant to Special Condition 7, above, then NSPI and the wholesale customer shall attempt to negotiate an adjustment to the CCF for the Internal Resource or External Resource, as applicable. If NSPI and the wholesale customer are unable to agree on an adjustment to the CCF, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

WHOLESALE MARKET NON-DISPATCHABLE SUPPLIER SPILL TARIFF **Page 1 of 2**

ADMINISTRATION CHARGE

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of suppliers supplying wholesale customers} * 12}$$

This charge will be $~~2,409.46~~2,487.77 per month.

ENERGY CREDIT

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs of ~~8.919~~6.736 cents per kilowatt hour as approved for use with the GRLF rate.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the administration charge.

AVAILABILITY

This tariff is available for use by, independent non-dispatchable electric generators serving the Wholesale Market. The tariff is applicable to scheduled "spill energy," under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to the Open Access Transmission Tariff (OATT) imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service. Spill capacity will be reviewed periodically and adjusted as required.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

2026 Annually Adjusted Rates Confidential Appendix I has been filed electronically.

Date: October 15, 2025
To: Annually Adjusted Rates Stakeholders
From: Regulatory Affairs, NS Power
Subject: NS Power Proposal for Changes to 1P-RTP Tariffs

In advance of its 2026 Annually Adjusted Rates (AAR) Application, to be filed by November 7, 2026, Nova Scotia Power Inc. (NS Power, Company) is seeking stakeholder feedback on its proposed changes to the calculation of the One-Part Real Time Pricing (1P-RTP) Adders made in response to the Board's directive on the Company's 2025 AAR Application (M11989). The proposed change is due to challenges in the calculation of avoided fuel costs in the increasingly complex air emission market, as indicated by the Company in section **5.1 Proposed Adjustment to Calculation of Avoided Fuel Costs** of the 2025 AAR Application.[1]

NS Power's Proposal

1. The adjustment for the projected imbalance in the recovery of the avoided fuel costs should be eliminated. The energy charges under these tariffs should be made of hourly marginal costs. The fixed cost adders should include only the non-fuel costs.

2. Beyond the upcoming 2026 AAR Application, the 1P-RTP tariffs should no longer be adjusted annually, but rather set as part of General Rate Applications as is the case with the Open Access Transmission Tariff (OATT) and the Renewable to Retail Distribution Tariff.

The issues arising from the continued use of the adjustment for the projected imbalance in the recovery of the avoided fuel costs in the 1P-RTP fixed cost adders were highlighted in section 5.1 Proposed Adjustment to Calculation of Avoided Fuel Costs in the 2025 AAR Application. In its Decision on the 2025 AARs, the Board provided:

> NS Power identified issues in forecasting the cost to serve One Part-Real Time Pricing Tariff customers under the current method due to the required reduction in air emissions and the increasing amount of non-dispatchable generation sources. NS Power adjusted the SO2 emissions limits in the model but does not consider this to be a reasonable long-term solution. NS Power proposed to find a new methodology based on the application of marginal system fuel costs and review this methodology with stakeholders in upcoming consultations on the TVP structure of the AARs. The Board directs NS Power to review the issue no later than in the 2026 AAR application.[2]

NS Power's proposed departure from the use of avoided fuel costs under the 1P-RTP Tariff is justified for the following reasons.

[1] M11989 – 2025 Annually Adjusted Rates (AAR) NS Power Application November 28, 2024.
[2] M11989 – Board Decision, 319292, page 6. March 25, 2025.

1. The growing complexity of the air emission market makes the continued application of the current avoided fuel cost methodology increasingly difficult, it leads to volatile results, and therefore is unreliable.

    a. This is particularly true in the context of the small uptake of the 1P-RTP service where pursuit of precision in recovery of the avoided fuel costs from the 1P-RTP customers will have a limited benefit in terms of a more equitable apportionment of fuel costs to other rate classes compared to the computational challenges in trying to do so reliable for the 1P-RTP class.

2. The presence of the fuel cost adjustment in the 1P-RTP fixed costs adders has its roots in the avoided fuel costs methodology applied broadly to all the annually adjusted rates prior to 2017.

In its 2017 Decision on the Load Following Rate Setting Methodology, the Board eliminated the avoided fuel costs foundation of most of the AARs by replacing it with a marginal fuel cost concept providing as follows.

> On the issue of marginal fuel cost, there appeared to be general agreement that the current 25 MW decremental modelling approach to determine avoided costs was no longer valid and that the marginal fuel cost approach was more appropriate.[3]

The Board directed NS Power in its 2017 Decision to submit AARs using the following approach which has become a standard for setting AAR energy charges since that time.

> In addition, the Application is to separately include adjusted rates using the marginal fuel cost methodology applicable to the next MWh; i.e. using the current approach of a single annual marginal cost determined directly by the Plexos model, rather than on the basis of a load decrement.[4]
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> As a result, the GRLF, Shore Power, BUTU, Spill and EBS Tariffs, which used the 25 MW decrement cost estimate for determination of their energy charges, transitioned to the use of an annual average of forecasted hourly marginal costs. In addition to the marginal fuel cost component the energy charges under these rates also include non-fuel cost adders which do not have a fuel cost adjustment subcomponent as is the case with the 1P-RTP tariffs.

The proposed methodological adjustment will align the 1P-RTP tariffs with the costing approach used for other AARs.

[3] M08114 – Annually Adjusted Rates Load Following Setting Methodology (P-141), page 4.
[4] M08114 – Annually Adjusted Rates Load Following Setting Methodology (P-141), page 5.

Background on 1P-RTP Tariff Design and Operation

There are currently three 1P-RTP Tariffs in effect; one for each of the three voltage levels at which RTP customers may be served. The tariffs are:

1. One Part Extra High Voltage (EHV) RTP Tariff;
2. One Part High Voltage (HV) RTP Tariff; and
3. One Part Distribution Voltage RTP Tariff.

There is currently one customer subscribed under the HV RTP Tariff.

Each of these three tariffs include energy charges with two components: hourly marginal costs forecast 20 minutes ahead, and fixed costs adders, updated annually. The hourly marginal costs are determined in real time and are not subject to Board approval.

The adders are designed to:

- Recover the non-fuel related costs that would be incurred by NS Power in serving the eligible customers under each of the 1P-RTP tariffs; and

- Provide an adjustment for the projected imbalance in the recovery of the avoided fuel costs associated with serving the eligible customers under each of the 1P-RTP tariffs.

The fuel cost imbalance arises from employing hourly marginal costs, as opposed to hourly average avoided fuel costs, in energy charges on customer bills. Since the differential between hourly marginal and hourly avoided fuel costs can be volatile, the projected annual fuel cost imbalance can vary and cause fluctuations in the adders from one year to the next. As designed, the combined tariff components collect the overall intended costs.

Next Steps

Stakeholders are requested to provide comments on the proposed approach (if any), as outlined in this letter, by Friday, October 24, 2025, following which NS Power will address stakeholders' comments in consideration of its 2026 AAR Application to be filed by November 7, 2025.

Please be advised that the 1P-RTP and Shore Power Tariffs coming into effect in 2026 will no longer feature separate rates for the customers connected at the Extra High Voltage (EHV) and High Voltage (HV) transmission levels if the proposed change to eliminate the breakdown between these two transmission cost categories in the consensus Cost of Service Study (COSS), filed in the 2026-2027 GRA, is accepted by the Board. Instead, there will only be one transmission rate under the Shore Power Tariff and one 1P-RTP Transmission Tariff instead of two.