Nova Scotia Energy Board

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

M12551

2026 Annually Adjusted Rates (AARs)

NS Power
Reply Evidence

January 27, 2026

Non-confidential

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1.0 INTRODUCTION

On November 7, 2025, NS Power Incorporated (NS Power, Company) filed its Application for the 2026 Annually Adjusted Rates (AARs) with the Nova Scotia Energy Board (NSEB, Board). The Company requested approval of the following annually adjusted tariff rates for 2026:

- 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)

On December 22, 2025, NS Power filed responses to Information Requests (IRs) from the Consumer Advocate (CA), Industrial Group (IG), Municipal Electric Utilities (MEUs), NSEB, Renewall Energy Incorporated (REI), and the Small Business Advocate (SBA).

On December 24, 2025, the NSEB invited parties to submit comments on Port Hawkesbury Paper's (PHP) December 12, 2025 request for interim approval of the 2026 ELIADC Energy Charge. On January 19 and 20, 2026, the CA, IG, and the SBA filed comments on PHP's requested interim approval. As provided in the Company's January 14, 2026 comments, NS Power does not oppose the Board granting interim approval of the proposed 2026 ELIADC Energy Charge.

On January 20 and 21, 2026, NS Power received evidence and submissions on the 2026 AAR Application from the CA, MEUs, REI, PHP, and the SBA. Among the submissions, no party has opposed NS Power's proposed 2026 AARs, with the exception of REI's concerns related specifically to the SS Tariff. The Company addresses these concerns in Section 5.0 of this submission. The CA stated it "does not object to the application as filed."[1] The MEUs "support approval of the proposed 2026 [BUTU and Spill Tariff] charges as filed."[2] PHP's submission indicated its "support of the proposed 2026 ELIADC Energy Charge of $75.87/MWh as filed, with a requested effective date of January 1, 2026."[3]

The remaining matters raised in parties' evidence and submissions primarily concern administrative matters, including additional information requested by the parties. In the case of REI, their comments focused on Renewable to Retail (RtR) market-specific processes and tariff methodologies. In the following sections, NS Power responds to these remaining matters.

[1] M12551, Exhibit N-8, NS Power 2026 AARs, CA Submissions, January 20, 2026, page 1.
[2] M12551, Exhibit N-10, NS Power 2026 AARs, MEUs Submissions, January 20, 2026, page 2.
[3] M12551, Exhibit N-11, NS Power 2026 AARs, PHP Submissions, January 20, 2026, page 1.

2.0 EVIDENCE OF THE CONSUMER ADVOCATE

The CA offered "limited comments"[4] on specific modeling and tariff methodology items and requested the Company "confirm whether any of the Consumer Advocate's understandings or assumptions as stated above are incorrect or incomplete."[5] Each of these items are addressed below.

In its evidence and submissions, the CA stated:

- Modelling of Power Imports: The Consumer Advocate observes that there appears to be some inconsistency between the historical average deliveries for New Brunswick imports, and the volumes reported as model outputs in response to CA RIR-7 (Exhibit N-2). The Consumer Advocate understands that forecast NB import volumes are reduced relative to the historical average because (1) there is now greater availability of lower-priced ML Surplus power and (2) NB Import prices are generally correlated with gas prices and thus are unlikely to be price-advantaged when gas prices are high. The Consumer Advocate accepts this approach, but would suggest that NS Power avoid resetting the NB Import limit to reflect current (lower) volumes in the historical average, which could unreasonably limit forecast NB Imports, particularly on a monthly basis. The Consumer Advocate further notes that the volumes for ML Surplus energy reported in Appendix A4 (p. 17) differ from the limits reported in Exhibit N-2, CA RIR-7. The Consumer Advocate understands that the information in Appendix A4 is incorrect, and the information in Exhibit N-2 is correct, and wished to bring this discrepancy to the Board's attention.[6]

NS Power Response:

NS Power adjusts NB Import volumes using a three-year average specified in the Fuel Adjustment Mechanism (FAM) Plan of Administration, Appendix B, to acknowledge changes in the market but also considers new information when forecasting, including possible changes in import availability, contracted imports, and changes to transmission availability. NS Power believes this

[4] M12551, Exhibit N-8, page 1.
[5] M12551, Exhibit N-8, page 2.
[6] M12551, Exhibit N-8, page 1.

approach is appropriate as it reflects the availability of import energy and produces a realistic import energy forecast from New Brunswick and the ISO New England. The dispatch optimization model will choose the most economic import based on the system requirements and the availability of those imports at that time.

There was an error in Appendix A4 which incorrectly listed the limits of Maritime Link on-peak surplus energy. NS Power agrees with the CA and submits that the information provided in the Company's response to CA IR-7 is correct.

With respect to changes in 1P-RTP methodology, the CA provided:

> - Change to 1P-RTP Method: The Consumer Advocate understands that currently the 1P-RTP rate is only available to customers for the "top energy block" representing a portion of their load, and that NS Power would thoroughly review any new customer application for additional load to be served under this rate to ensure that it is truly a price-sensitive load. In this regard, the Consumer Advocate refers to the following statement from NS Power's 2018 AAR Application (M08383):
>
>   > As the 1P-RTP tariff does not use the fuel cost component of the LF rate, its rate calculations are not affected by the consideration of a choice between the avoided costs of a 2 MW load decrement and the marginal cost of the next MWh.
>
>   The Consumer Advocate understands that this statement relates to the distinction between a 2 MW and a 25 MW load decrement method, and was not intended to state that the method for calculating the 1P-RTP tariff rate would be unaffected by any contemporaneous change in other AAR rate calculation methods from avoided cost load decrement to marginal cost.
>
>   Accordingly, the Consumer Advocate is satisfied that the proposed change in the 1P-RTP tariff rate calculation method to marginal costs is reasonable given that NS Power only allows this rate to be available for the "top block" of a customers' load, with assurance that the load is price-sensitive. And further, that the amount of load served on 1P-RTP is currently and likely to remain small enough that curtailment of the load would not be sufficient to either materially change NS Power's resource requirements or change non-marginal fuel costs, such as unit commitment costs. For portions of the customer's load that are not price-sensitive, the customer should be served

> on a rate schedule that includes full fuel costs which would include recovery of unit commitment and other non-marginal fuel costs.[7]

<u>NS Power Response</u>:

Currently there is one customer taking service under the 1P-RTP Tariffs and that customer takes this service in concert with an above-the-line (ATL) tariff, with the 1P-RTP service being applied to the customer's top energy block. While NS Power works with customers who may take service under a 1P-RTP Tariff to support their efforts to shift load and reduce costs, there is no requirement that the customer's service uptake be split between the 1P-RTP and any other tariff, nor that the customer demonstrates that its 1P-RTP load be "price sensitive." Customers subscribing to the 1P-RTP tariff are free to choose what portion of their load should be placed under other tariffs. The effect of the service offering under the 1P-RTP Tariff on NS Power's costs and the participating customer is subject to regulatory oversight through the 1P-RTP Report, which is filed annually to the NSEB, "setting out the revenue received from customers on this rate for the previous year, the cost of providing service to customers on this rate during the previous year and the estimated revenue NS Power would have received the previous year if customers on this rate had not opted to take service under it."[8]

In response to the CA's statement that, "[t]he Consumer Advocate understands that this statement relates to the distinction between a 2 MW and a 25 MW load decrement method, and was not intended to state that the method for calculating the 1P-RTP tariff rate would be unaffected by any contemporaneous change in other AAR rate calculation methods from avoided cost load decrement to marginal cost,"[9] the Company confirms that CA's interpretation of the quoted statement from the 2018 AAR is correct. The change in the LF rate setting methodology in 2018 did not have any

[7] M12551, Exhibit N-8, pages 1-2.
[8] M05942, NSPI Time of Use Real Time Price Rates, Decision, NSUARB-NSPI-P-872, June 23, 2000, page 13.
[9] M12551, Exhibit N-8, page 2.

direct effect on the determination of the rates under the 1P-RTP Tariffs as they were determined through a separate and an independent calculation process.[10]

The CA is correct that the current and forecast subscription to this tariff is relatively small and unlikely to "materially change NS Power's resource requirements or change non-marginal fuel costs, such as unit commitment […]."[11] However, as noted above, the tariff billing approach and the price-sensitivity of the load are not requirements of the tariff.

[10] The fuel cost adjustment for the imbalance in the recovery of the avoided fuel costs associated with serving the 1P-RTP customers is based on the load of the customers eligible for service under each of the three 1P-RTP tariffs. This eligible load changes from year to year and therefore differs from the fixed 25 MW decrement load used in determination of the energy charge under the LF rate.

[11] M12551, Exhibit N-8, page 2.

3.0 EVIDENCE OF THE SMALL BUISNESS ADVOCATE

The SBA framed its evidence and submissions around risk allocation, administrative cost discipline, and process considerations.

The SBA provided:

> **Risk Transfer**
>
> The SBA recognizes that the AARs have historically included updates to marginal cost rates and administrative charges, however, there remains the possibility of asymmetric risk in the presence of highly volatile marginal costs forecasts (24% decrease from a number of the 2025 approved AARs) and data limitations due to the cyber incident. When forecast assumptions do not align with outcomes, bundled service and small business customers absorb the risk by bearing the residual outcomes of the updated rates. The SBA submits that transparency regarding forecast risk is important to understand and should be addressed by providing class level rate impacts from the proposed AAR rate changes.[12]

<u>NS Power Response</u>:

Under the established ATL and below-the-line (BTL) rate setting and true-up processes, variances between forecast and actual marginal fuel costs flow through to ATL customers through the FAM. BTL customers are not affected by the marginal cost true-up under the FAM, however, BTL customers bear the risk of being over or under-charged under the forecast marginal cost charges. The fuel cost transfer between ATL and BTL rate classes can be both upward and downward adjustments under the FAM. However, the risk exposure of the BTL rate classes is greater, under the symmetric fuel cost transfer, because transferred amounts represent a greater portion of the BTL class revenues than those of the ATL classes. The BTL class revenues before accounting for the ELIADC and BUTU, which are subject to the true-up of fuel costs, are forecast to represent 1.9 percent of the ATL revenues in 2026 and 2.7 percent in 2027, accordingly.

[12] M12551, Exhibit N-9, NS Power 2026 AARs, SBA Submissions, January 20, 2026, page 2.

The SBA provided:

> **Cross Subsidization**
>
> The SBA also notes the request for the deferral of Renewable-to-Retail (RtR) costs is being made without knowing the magnitude nor any explicit details regarding the timing of recovery of the deferred amount. The SBA recognizes that NS Power's ability to forecast these costs is dependent upon the development of the RtR framework which is still evolving. However, while the AAR process is not the place to define the recovery mechanism for deferred RtR costs, it is appropriate to acknowledge that the absence of a clearly defined recovery mechanism may create unintended cross-subsidization across time periods and among customer classes.[13]

NS Power Response:

NS Power acknowledges the SBA’s concern and agrees that the magnitude and timing of recovery of RtR costs cannot yet be precisely defined, given that the RtR framework and associated market arrangements are still under development. It is anticipated that ongoing regulatory processes (e.g. M12588, CI C0053699 Renewable to Retail Implementation) and progress with respect to the development of the RtR market will provide increased clarity as to the incurrence and recovery of the associated costs going forward.

NS Power notes that the deferral of any costs, including any associated financing costs, for the RtR market are the responsibility of the LRS and are intended to be recovered exclusively from the RtR market, once active, and not be borne by other customer classes. However, should the RtR market fail to come to fruition or to endure for the length of time required to recover those costs, those costs would be borne by customers more broadly. The Board has already considered, and declined, the use of alternative risk-mitigation mechanisms (such as a letter of credit in M11874). This uncertainty is precisely the reason deferral treatment is being proposed. In that context, the risk allocation identified by the SBA is not created by this deferral request but by the uncertainty surrounding the development of the RtR market.

[13] M12551, Exhibit N-9, page 2.

Further, the purpose of the proposed deferral account is to ensure transparency and regulatory oversight of these costs, not to predetermine the manner in which they will ultimately be allocated. When NS Power brings forward the deferral for recovery, the quantum, timing, and recovery mechanism, including the inter-class allocation issues will be fully tested before the Board.

The SBA provided:

> **Administrative Costs**
>
> With respect to administrative costs, the SBA recognizes that the Board has previously permitted escalation of administrative costs by an inflationary factor in M09866. The factor utilized in this proceeding of 3.25% is higher than that of the Statistics Canada reported inflation of 2.2%. NS Power has stated that the inflationary factor utilized in the 2026 AAR Application is more than just inflation and is based on factors that affect its ability to stay competitive in the job market. While the proposed escalation is in relation to administrative charges, the SBA submits that further justification may be required to ensure that administrative cost discipline is being upheld.[14]

NS Power Response:

NS Power notes the SBA's observation regarding the 3.25 percent escalation factor applied to AAR administrative charges. As described in the Company's responses to NSEB and SBA information requests,[15] this factor, unlike Statistics Canada's inflationary rate, reflects more than general cost-of-living adjustments. The 3.25 percent is representative of the 2026 forecast increase in NS Power's salary costs relative to the administrative function of the AAR tariffs. The 2026 forecast AAR administrative costs reflect market competitiveness considerations, merit-based progression, and retention measures so that compensation remains competitive and supports attracting and retaining the skills required to administer the AAR tariffs.

[14] M12551, Exhibit N-9, pages 2-3.
[15] Please refer to NSEB (NSPI) IR-12 and SBA (NSPI) IR-1, SBA (NSPI) IR-2, and SBA (NSPI) IR-5 in this proceeding.

4.0 EVIDENCE OF THE MUNICIPAL ELECTRIC UTILITIES

The MEUs' evidence and submissions relate to the implementation of billing arrangements under the BUTU and Spill Tariffs and reflect constructive engagement with NS Power on administration of those tariffs.

Regarding the choice of non-reciprocal billing arrangements, the MEUs' evidence provides that, subject to further discussion and information between the parties, "the MEUs and the Alternative Resource Energy Authority ("AREA") intend to have the full output of the Ellershouse Wind Farm applied against MEU consumption in a non-reciprocal billing arrangement"[16] and "[a]s a result, the MEUs are no longer requesting the flexibility to choose between reciprocal and non-reciprocal billing arrangements on an annual basis, and support the consistent use and implementation of a non-reciprocal billing arrangement in accordance with the legislation's removal of any reciprocal requirement for BUTU and Spill energy."[17]

<u>NS Power Response:</u>

The Company welcomes the clarity provided by the MEUs with respect to the MEUs' intentions for non-reciprocal billing arrangements going forward. NS Power and the MEUs continue to discuss issues associated with implementing the change to non-reciprocal billing. This change requires amendments to the Company's forecasting and development by the MEUs of a new process for delivery of hourly load and spill forecasts. Preparation of hourly load and wind generation forecasts will be more challenging under the non-reciprocal billing arrangement because generation spill will become more volatile.[18] NS Power sees the development of such a

[16] M12551, Exhibit N-10, page 2.
[17] M12551, Exhibit N-10, page 3.
[18] Under the reciprocal billing arrangement, the bottom energy block of MEUs, associated with power deliveries from the wind facility, is set at a fixed level of an average annual kW production of the wind facility. Since most of the hourly MEUs' load exceeds this threshold, hourly load is forecast at a constant level throughout the year, and the spill is a difference between the hourly generation forecast and the bottom energy block threshold. The forecasting dynamics under the non-reciprocal billing arrangements get more complicated because hourly spill becomes a function of not just one but two variables: hourly load and hourly generation.

forecast as a necessary precondition for the implementation of non-reciprocal billing for the MEUs.

NS Power and the MEUs continue to discuss the required changes to processes to enable the shift to non-reciprocal billing.

5.0 EVIDENCE OF RENEWALL ENERGY INC.

REI framed its evidence and submission around the use of the proposed Cost of Service Study (COSS) methodology, RtR Tariff review and design, SS Tariff calculations, and proposed additional marginal cost data reporting. For added context, and as described in Section 7.0 of the Application, REI's most recent Board-approved deadline for first selling renewable low-impact electricity under its license is March 31, 2027. Consistent with this timing, the 2026 AARs were developed on the assumption of no RtR market activity during the 2026 calendar year, and recovery under the RtR Tariff constructs is anticipated to begin in 2027; on, or before, the most recent deadline. While it is recognized that RtR service may commence late in Q4 2026, any such RtR market activity is expected to be limited in duration and scale and would therefore be expected to have little or no effect within the 2026 calendar year.

Consistent with the themes raised in REI evidence and submissions, REI made four requests. The first of which provided:

> 1. Recalculate the 2026 AAR rates using the most recently approved COSS methodology rather than the unapproved 2026 COSS, or alternatively, make the 2026 AAR rates interim and subject to adjustment based on the Board's final determination in the 2026-2027 GRA proceeding (M12451), with any adjustments to be implemented through a compliance filing.[19]

<u>NS Power Response:</u>

The Company understands the concerns raised by REI with respect to the COSS basis for the 2026 AARs. While, as part of the 2026-2027 General Rate Application (GRA) (M12451), the proposed cost of service methodology remains open to the Board's final determination, the 2026 COSS was developed through a collaborative process with Customer Representatives who, along with NS Power, ultimately reached consensus on the 2026-2027 GRA proposed by the Company. Notably,

[19] M12551, Exhibit N-12, NS Power 2026 AARs, REI Submissions, January 21, 2026, pages 11-12.

REI which was an intervenor in M12451, did not comment or raise any concerns in that proceeding regarding the proposed 2026 COSS.

Should the Board's final determination in M12451 differ from the proposed 2026 COSS, any resulting AAR impacts can be addressed through a compliance filing in this proceeding. This sequencing is consistent with the Board's approach in the Company's 2026 Demand Side Management Cost Recovery Rider (DCRR) Application[20] and avoids delayed approval of the 2026 AARs, pending resolution of broader cost allocation matters.

REI's second and fourth requests are interrelated, with request 2 proposing changes to the RtR tariff framework and request 4 seeking expanded marginal cost reporting to assess forecast accuracy and rate impacts under both the current and any potential revised framework. REI's second and fourth requests were:

> 2. Initiate a tariff amendment proceeding to consider and amend the RtR tariffs by no later than March 31, 2026, to address the changes in cost allocation, the implementation of monthly marginal cost pricing, and the inclusion of a true-up mechanism.
>
> //
>
> 4. Provide forecast versus actual monthly and hourly marginal costs for 2021–2026 and explanations for variances greater than ±10%, in a format comparable to Appendix A2, within the 2027 AAR Application.[21]

<u>NS Power Response:</u>

In relation to REI's second request, NS Power and REI agree[22] that the AAR process is designed to update tariff rates using established methodologies; it is not the appropriate forum to introduce structural tariff redesign. As described in Section 7.0 of the Application, the existing RtR tariffs

[20] The Board's Interim Order in the 2026 DCRR proceeding (M12521) approved the continuation of the 2025 DCRR "until further order of the Board in this matter, or as part of NS Power's ongoing general rate application."
[21] M12551, Exhibit N-12, page 12.
[22] At page 4 of its Submissions, REI provided "REI acknowledges that the AAR process is not necessarily the proper venue for revising tariff structures."

reflect a framework that aligns marginal cost-based energy pricing with embedded-cost recovery safeguards, including the EBS, SS, and RTT Tariffs. Further, the development of, and participation in, the RtR market remains transitional, as evidenced in Sections 7.0 and 7.4 of the Company's Application. Initiating a bespoke tariff redesign proceeding at this stage of market development, and particularly while key matters such as the role of the Nova Scotia Independent Energy System Operator (IESO-NS), the ongoing RtR market implementation, and the Board's final determination on the proposed COSS are in flux, would be premature. In addition to these foundational components, several RtR-specific initiatives are expected to be reviewed with the Board and stakeholders in 2026, including the Interruptible Service Pilot[23] and the design of tariffs, procedures, or standards of conduct to enable behind-the-meter and net metering in the RtR market.[24]

In light of this, NS Power submits that consideration of any structural tariff enhancements is best sequenced following greater operational experience in the RtR market, greater regulatory certainty regarding cost of service matters, resolution of the ongoing RtR matters (as described above), and a more complete understanding of the implementation of the next phase of the IESO-NS transition. To this end, the Company suggests this issue is more appropriately addressed in NS Power's future review of existing AARs' suitability for a time-variable rate structure[25] as this process will provide the forum for a broad review of the fuel cost components of AARs, consistent with the comments provided in REI's submission. With respect to REI's concern around variability of pricing,[26] the Company notes that the nature of utility pricing and tariffs is that these are subject to change within, and across, years as cost drivers and market conditions change.

Concerning REI's fourth request, the Company's position is that these annual applications already provide the appropriate level of marginal cost information, and which is purpose-fit for the AAR process. As detailed in Section 2.0 and Appendices A2 through A7, the AAR Application includes the derivation of the 2026 marginal cost forecast, key modeling assumptions, sensitivity analyses

[23] M12551, Exhibit N-1, NS Power 2026 AAR Application, November 7, 2025, Section 7.4, page 37.
[24] M12339, NSEB Board Decision, 325855, November 19, 2025, page 35, para. 68.
[25] M11989, NSEB Board Decision, 319292, March 25, 2025, page 6.
[26] M12551, Exhibit N-12, pages 7-8.

directed by the Board, and monthly marginal cost values underlying the annual average applied in the tariffs.

NS Power does not support a requirement to provide historical reconstructions or narrative explanations for monthly or hourly deviations between forecast and actual marginal costs. Such reporting is administratively burdensome, impossible to conduct robustly at hourly or daily granularity, and would provide limited, if any, incremental value for AAR decision-making. Variances between actual and forecasted hourly marginal costs would be caused by numerous changes to the power system, not limited to load, prices, unit availability, and wind. These changes can be different from forecasted marginal prices for any combination of these reasons making any information gathered from this type of process both burdensome, non-comprehensive, and non-beneficial.

The forecast is developed based on the best information and assumptions available at the time and is in alignment with the FAM Plan of Administration forecasting methodology. It is also noted that this is especially relevant in consideration of the earlier portions of the requested analysis period (2021-2026) which were affected by exceptional geopolitical and market conditions.

Consistent with the focus of the RtR Tariffs themselves, which apply annual pricing informed by monthly fundamentals, NS Power respectfully submits that summary-level monthly and annual comparisons are the appropriate lens for evaluating forecast performance, and does not support providing expanded historical or hourly variance reporting as part of 2027 AARs or future AAR Applications.

REI's third request provided:

> 3. Provide a compliance filing addressing the noted errors in the SS Tariff Demand Charges, at Appendix F3.[27]

[27] M12551, Exhibit N-12, page 12.

NS Power Response:

1. Treatment of Ancillary Service Costs

Calculations in Appendix F3 reflect the correct amount of the "Load Following" cost of $21,166 in cell C23. The cost of $21,166 matches the amount displayed in cell E14 in tab "Anc Serv – Fig 6-8" of 2026-2027 GRA SR-01 Att 11.xlsx filed in M12451. NS Power was not able to find the figure of an alternate "Load Following" cost of $30,213 in M12451 GRA COSS Sch 12-A, Att 11 OATT, as indicated by REI.

In reviewing calculations in Appendix F3; however, NS Power identified an incorrect input of Operating Reserve – Supplemental (10 min) cost of $16,601 in cell C25. The correct cost of matching that in cell E18 of tab "Anc Serv – Fig 6-8" is $12,328. Correcting this data input error increases the proposed demand charge of $5.452 per kW to firm service to $5.616 per kW. Please refer to the following attachments reflecting this correction:

- Attachment 1 – Revised 2026 Appendix E3
- Attachment 2 – Revised 2026 Appendix F3
- Attachment 3 – Revised 2026 Appendix I EO
- Attachment 4 – Revised Standby Service Tariff (Redline)
- Attachment 5 – Proposed Revised Standby Service Tariff (Clean)
- Attachment 6 – Revised 2026 Wholesale Market BUTU Tariff (Redline)
- Attachment 7 – Proposed Wholesale Market BUTU Tariff (Clean)

NS Power requests that the revised 2026 Standby Service Tariff in Attachment 5 and the revised 2026 Wholesale Market BUTU Tariff in Attachment 7 replace those filed on November 7, 2025 consistent with REI's assertion that "[t]he "Load Following" and other ancillary amounts used in Appendix F3 must match the values and exhibit references in the GRA record."[28]

[28] M12551, Exhibit N-12, page 10.

2. Proposed Amendment to Firm Service Charge to include Interruptible Service Costs

The current calculation of the firm service charge under the SS Tariff is incorrect by not accounting for the interruptible service credit as a cost applicable to the firm RtR market customers. The firm charge under the SS Tariff in effect today is based on NS Power's total generation system costs which already include the benefit of avoided generation capacity costs created by the provision of interruptible service in the bundled market. Had the current bundled service interruptible customers of NS Power always taken firm service, NS Power would not have avoided installing more generation capacity and generation costs would have been higher. To keep the firm bundled service customers' rates aligned with the firm service costs and also to ensure that the firm bundled service customers are indifferent to the presence of the interruptible service on the system, the cost of interruptible service must be recovered. This is achieved by making the firm bundled service customers responsible for the payment of the costs of crediting the interruptible customers on the system.

The same logic must apply to the unbundled service market. For the firm service charge under the SS Tariff to be tenable going forward it must reflect the cost of interruptible service. Otherwise, the bundled service customers would subsidize the RtR market.

The issue is expected to come to a head before March 31, 2027, if and when an interruptible bundled service customer, along with other firm service customers, transitions to the RtR market and continues to get credited for its interruptible service. Absent the proposed adjustment to the current firm service charge, NS Power will under recover its generation costs in serving the firm RtR customers and there will not be a justification for payment of the proposed credit of $14.053 per kW to the interruptible customer.

6.0 EVIDENCE OF PORT HAWKESBURY PAPER LP

PHP's evidence and submissions indicated "support of the proposed 2026 ELIADC Energy Charge of $75.87/MWh as filed, with a requested effective date of January 1, 2026."[29] PHP also provided more general responses within their evidence and submissions to parties' comments on PHP's requested interim approval of the 2026 ELIADC Energy Charge.

[29] M12551, Exhibit N-11, page 1.

7.0 CONCLUSION

NS Power respectfully submits that:

1. With the exception of REI's concerns related specifically to the SS Tariff, which the Company addressed in Section 5.0, no party opposed the Company's proposed annually adjusted tariff rates for 2026, as filed;

2. With respect to REI's submission, and consistent with Section 7.0 of the Application, the latest Board-approved deadline for REI to first sell renewable low-impact electricity under its licence is March 31, 2027. In alignment with this timing, the 2026 AARs were developed on the assumption of no RtR market activity in 2026, and recovery under the RtR tariff constructs is anticipated to begin in 2027; on, or before, the March 31 deadline. While it is recognized that RtR service may commence late in Q4 2026, any such activity is expected to be limited in duration and scale, and would therefore be expected to have little or no effect within the 2026 calendar year; and

3. The remaining matters raised in the parties' evidence and submissions are administrative or informational in nature and do not detract from, or hinder, the Board's review and approval of the 2026 AARs, as filed.

8.0 RELIEF SOUGHT

In addition of the relief sought in the Application, NS Power respectfully requests that the proposed 2026 charges under the BUTU and SS tariffs, be amended as per Attachments 5 and 7 to this submission.

2026 AAR Reply Evidence Attachment 1 has been filed electronically only.

2026 AAR Reply Evidence Attachment 2 has been filed electronically only.

2026 AAR Reply Evidence Attachment 3 has been filed electronically only.

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~~ 5.616 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:

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

Where:

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

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

  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.

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

$5.616 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	1.34	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.

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	$~~2.792~~5.616
Total	**$~~7.160~~11.868**

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.

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	$5.616
Total	**$11.868**

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.