Nova Scotia Energy Board

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

Nova Scotia Power
Application for Approval of an Above-the-Line Tariff Applicable to Port Hawkesbury Paper

December 29, 2025

NON-CONFIDENTIAL

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

Nova Scotia Power Inc. (NS Power, Company) is applying to the Nova Scotia Energy Board (NSEB, Board) for approval of the Extra Large Industrial Dispatchable (ELID) Tariff, an above-the-line (ATL) tariff available to Port Hawkesbury Paper LP (PHP, Customer). It is intended that PHP will subscribe to this Tariff on, or before, January 1, 2027 as the current term of the Extra Large Industrial Active Demand Control (ELIADC) Tariff, under which PHP currently takes service, will expire at the end of 2026. Should the Board not approve an ATL tariff applicable to PHP or should PHP determine it will not subscribe to the ATL tariff as approved by the Board, an alternative course of action will be required for service to PHP in 2027.

The Tariff is based on the Large Industrial (LI) Tariff under which the Company's large industrial customers are served. The ELID Tariff includes a new rider, the Dispatchable Rider (DR), as a component of service to PHP (referred to under the ELIADC Tariff as Active Demand Control (ADC)). Under this Rider, NS Power has a general duty to serve just as it does to other ATL customers but will dispatch PHP's load in response to system conditions to reduce the cost to serve PHP and enable the system cost savings created by PHP's load flexibility to be credited to PHP. Recognizing that the dispatch of the PHP load and administration of this Tariff results in costs at NS Power, the Tariff includes a Customer Charge to provide for the recovery of these costs from PHP.

The Tariff costing and billing parameters are applied as noted in the Settlement Agreement (SA) which underpins the Company's 2026-2027 General Rate Application (GRA) (M12451) currently before the Board. The SA has been provided to the Board in M12451 as Attachment 1 to NSEB IR-001 and is attached to this Application as Attachment 4.

2.0 TARIFF COMPONENTS

Key elements of the ELID Tariff, provided as Attachment 1 to this Application, include the following:

- Customer Charge
- Demand Charge
- Energy Charge
- Interruptible Service
- Dispatchable Rider
- Other Applicable Riders
- Billing Provisions
- Tariff Term
- Treatment of Energy Production from the Goose Harbour Lake Wind Farm (PHP Wind Ltd., PHPW)
- PHP Deferral

Discussion of each of these elements follows.

2.1 Customer Charge

The Customer Charge is designed to recover the costs associated with the provision of dispatch service to PHP and to administer the Tariff. Tasks required to support the Tariff include, but are not limited to, the following:

- Development, management, and refinement of Operating Procedures.
- Engagement with PHP on development of PHP dispatch schedule.
- System Operator engagement with PHP on dispatch.
- Regulatory engagement and reporting and ad-hoc customer requests.

- Engagement with PHP on development of forecast and actual DR benefit (DR credit).
- Periodic PLEXOS and PortOps modeling and report preparation.
- Real-time optimization of PHP load to achieve the most economic system dispatch.
- Providing dispatch instructions to PHP based on economic dispatch optimization results and real-time system conditions.

The proposed monthly Customer Charge included in the Tariff is $10,000 for each of 2026 and 2027 based on the cost of required staff and software. Please refer to Attachment 3 for the development of this monthly charge. Following the Board's Decision in this matter, in accordance with other ATL tariffs, it is proposed that the ELID Tariff Customer Charge will be set through future GRA proceedings.

2.2 Demand Charge

In accordance with the Company's Cost of Service Study (COSS), demand-related costs are proposed to be allocated to the ELID Tariff class based on PHP assigned demand at the time of the three coincident peaks (3CP). Recognizing that PHP demand during the 3CPs will be determined by the Company and PHP under the Dispatchable Rider, it is proposed that determination and billing of this figure will differ from the LI in two respects:

(1) As proposed, rather than relying solely on PHP metered data at the time of the 3CPs, the setting of the PHP coincident peaks for costing and pricing purposes will require judgment as to the level of demand which is representative of PHP system usage and provides for fair allocation of demand-related costs across ATL classes. Given that PHP coincident demand could swing based on the Company's dispatch between very low demand (e.g. 8 MW) and very high demand (e.g. 160 MW), depending largely on system load conditions and the level of PHP demand that produces the lowest cost to serve the system in real time (as enabled by the Dispatchable Rider), it is proposed that the PHP demand determinant be reviewed and

set as part of the GRA process or, as applicable, Fuel Adjustment Mechanism (FAM) or other related proceedings, if occurring between GRAs.

(2) Consistent with the foregoing, it is proposed that the assumed costing/billing demand also be adopted and applied for billing purposes throughout the year. (i.e. the PHP 3CP figure employed for Tariff costing and pricing would also be applied for billing purposes essentially making the demand cost recovery a fixed charge).

For 2026 and 2027, the SA provides "The COS has been prepared on the basis of the following PHP load characteristics: a) PHP's firm load at 8MW at the three coincident peaks; b) PHP's firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP metered load at the time of NSP's 3CP […]".[1] The 65 MW figure has been used in the COSS proceeding modeling (M11475), which preceded the GRA and is included in the GRA as Appendix 12. As noted, the 65 MW figure reflects the figure used in prior forecasts for estimating the demand of PHP at 3CP based on PHP's historical demand at the time of system peak as dispatched by the Company. The Company understands that PHP's view is that the three coincident peak demand determinants applicable to PHP should be set at the firm demand level of 8 MW in light of the Company's control of PHP's load at times of system peak. In light of the provisions of the GRA Settlement Agreement and well-established NS Power cost of service treatment, the Company does not agree.

Consistent with the pricing of other ATL Tariffs, demand pricing for the Tariff will be updated in GRAs. As part of these processes, or other matters wherein class demand affects costing/pricing of energy (e.g. FAM proceedings), the costing and billing determinants applicable to PHP will need to be revisited and reset as appropriate in a manner which reflects PHP's actual operation and provides for fair allocation to this class of the Company's cost of service.

The proposed demand charges for 2026 and 2027 are $12.872 per kVA per month and $14.310 per kVA per month, respectively. For information on the PHP cost of service treatment assumed

[1] Please refer to Attachment 4, pages 11-12.

in the GRA, please refer to M12451 SR-01 Attachment 1a to 1c, SR-01 Attachment 2, SR-01 Attachment 3, NSPI (CA) IR-001, and the SA (provided as Attachment 4 in this Application).

2.3 Energy Charge

The Energy Charge under the ELID Tariff will apply to all energy supplied to PHP in excess of the Subject Energy Amount[2] deemed to be provided pursuant to the Power Sales Agreement issued under Section 4AA (now Section 24) of the *Electricity Act* (Act). For 2026 and 2027, PHP's allocated embedded costs, energy costing, and billing determinants were determined by applying the Company's proposed GRA COSS and are further described in the SA as, "PHP energy will be based on PHP's forecast usage for the test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm. The same load characteristics are applicable to the base cost of fuel model as well."[3] For 2026, the assumed PHP energy consumption in the GRA COSS is 810.5 GWh, and for 2027, the assumed PHP energy consumption in the GRA COSS is 304.3 GWh, with the reduction in 2027 attributable to the forecast displacement of NS Power electricity supply by energy from the PHPW Power Purchase Agreement (PPA). For further details on the contractual arrangements governing the Subject Energy Amount, refer to the Power Purchase Agreement and Power Sales Agreement provided in M12184 NSPI (IG) IR-1 Attachment 1.

The proposed energy charges for 2026 and 2027 are 9.977 cents per kWh and 11.240 cents per kWh, respectively. For information on the PHP cost of service treatment assumed in the GRA, please refer to M12451 SR-01 Attachment 1a to 1c, SR-01 Attachment 2, SR-01 Attachment 3, NSPI (CA) IR-001, and the SA (provided as Attachment 4 in this Application).

The ultimate energy charges are also subject to change based on the outcome of the ongoing Court proceedings regarding PHP's responsibility for the payment of costs associated with the new Maritime Link Federal Loan Guarantee (FLG2).

[2] Subject Energy Amount refers to the defined term within the prescribed Power Sales Agreement under s. 4AA (now s. 24) of the *Electricity Act*.
[3] Attachment 4, page 11, "PHP Treatment," item b.

2.4 Interruptible Service

The ELID Tariff interruptible service provisions, for the most part, adopt the LI Interruptible Rider (LIIR) terms with minor text updates drawn from the ELIADC Tariff interruptible service provisions. With respect to the pricing of interruptible supply to PHP, the SA provides "The dollar value of the Interruptible credit to be applicable to PHP's interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit."[4]

As noted in the SA, for 2026 and 2027, the proposed interruptible credit applicable to PHP is the same as proposed for the LIIR: $7.638 per kVA and $7.667 per kVA of interruptible service for 2026 and 2027, respectively. It is important to note that this is a significantly lower figure than would be applicable to PHP had the credit been developed in accordance with the Company's established practice for pricing of the interruptible credit ($13.107 per kVA demand coincident with system peak).[5] Subject to a Board Decision in this matter, it is anticipated the ELID interruptible credit will be revisited in the next GRA.

With respect to the SA priority interruptible service provisions, the Company's initial analysis of the priority interruptible service has determined the primary direct value of priority interruptibility is to reduce risk of interruption to other interruptible customers. However, in light of the size of this resource and access to it for many years, the potential negative effect of losing this tool during a period of system transformation, the recognized benefits of the dispatch of the PHP load by NS Power on system reliability, and the relatively low cost of acquiring priority interruptible service (approximately $500,000 annually as modeled in the GRA COSS), the Company considers this to be an area that requires more review and is premature to discontinue. As such, NS Power proposes

[4] Attachment 4, page 11, "PHP Treatment," item c.
[5] This is determined using the following formula: Winter Coincident Peak of ELID of 59,446 kW x Annual Levelized Avoided Peaker Cost of $160.44/kW / (57,000 kW winter month system coincident demand of ELID at customer's meter x Power Factor of 1.06383 of PHP x 12 months) = $13.107/kVA.

that priority interruptible service and the compensation to PHP, as modeled, be maintained until it can be revisited in the next GRA. In accordance with this, the ELID Tariff includes the following credits to be paid to PHP for the continuation of priority interruptible service.

ELID Priority Interruptible Credit	**reduction per kilovolt ampere reduction in demand charge**
Effective January 1, 2026	$0.764
Effective January 1, 2027	$0.767

Consistent with the provisions of the ELIADC Tariff and as available to LIIR subscribers, the ELID Tariff includes provision for PHP load to be held as Operating Reserve as required by system conditions. The interruptible notification processes, penalties for non-compliance, etc. are the same as the LIIR provisions.

2.5 Dispatchable Rider

The Dispatchable Rider (DR) will allow PHP to operate in a manner which reduces PHP's individual cost of service, enables NS Power to manage PHP's load in response to system conditions, reducing overall system costs, and compensates PHP for the value its load flexibility provides to the NS Power system. The structure of the Rider shields ATL customers from the significant incremental cost impacts that the system's largest customer can have on the system if not incented to operate in a manner which reduces overall system costs.

The DR is premised on the understanding that, absent the Rider, and as an ATL customer with demand and energy charges, PHP would generally be incented to operate at a high load factor (i.e. levelized load) across the year, as this mode of operation will reduce the per unit cost of electricity for PHP. However, for a customer with the load flexibility of PHP, a levelized load profile will, in general, not produce the optimal customer or system load profile as the Customer would be expected to consume equally across the year, indifferent to changes in the marginal cost of system supply. In light of the size of PHP load, running as a conventional ATL customer risks increasing costs for all ATL customers, including PHP. The Rider will serve to align the interests of all ATL customers. Given PHP energy and demand will be priced on an embedded cost basis consistent with other ATL customers, and because the cost of providing DR service is borne by PHP and the overall effectiveness of the tool is determined by PHP's performance, it is proposed that the value created by the dispatch of PHP load be credited fully to PHP.

The cost of the DR service (DR credit) is proposed to be included as a FAM cost for recovery from all ATL customers, including PHP. Subject to Board approval of this Application, it is expected changes will be required to the FAM Plan of Administration to recognize this and potentially other ELID Tariff elements. Because the cost of the service is based on the benefit the service provides to the system, ATL customers will be held harmless under the DR construct.

The Rider leverages the processes that have been developed between NS Power and PHP over the approximate six-year period wherein PHP has taken service under the ELIADC Tariff and provided Active Demand Control service to NS Power and NS Power customers. The Tariff reduces volatility faced by ATL customers as PHP load will be priced as an ATL customer in accordance with the Company's Board-approved Cost of Service model.

The Rider provides a potential material benefit to PHP in the form of the DR credit, a significant benefit to other customers through PHP's increased contribution to system costs as enabled by the embedded cost-based energy and demand pricing and minimizes risk to other ATL customers due to PHP load flexibility. The methodology to determine the dispatch value is relatively simple and transparent compared to the ELIADC Tariff processes and is anticipated to be less controversial. The actual system conditions that occurred throughout the year will be employed to calculate the system cost to serve PHP at a high load factor (i.e. the Customer Baseline), with the difference between this and the Company's actual system cost appropriately attributed to and credited to PHP.

Based on initial analysis completed in 2025 utilizing forecast data, the Company has estimated that for that period, if PHP load had been dispatched at 100 percent optimal, this service would have delivered approximately $7 to $11 million of savings to PHP in a year. In reality, this level of savings will be challenging to achieve as system conditions, customer production constraints/requirements, etc. will, at times, conflict with optimal load dispatch. Based on experience with the ELIADC Tariff, the Company estimates that the actual benefit that can be realized will be approximately half this amount. Regardless, unlike the ELIADC Tariff, the opportunity and benefit realized ultimately rest with PHP. As such, as proposed, all benefits created by PHP load flexibility during the year will flow to PHP. In this regard, dispatch service is comparable to interruptible service available to LIIR customers. The compensation for providing the service is quantified based on the system cost savings provided by the service and as such other ATL customers are held harmless.

Consistent with the ELIADC Tariff, PHP operations under the DR will be governed by Operating Procedures developed between NS Power, the System Operator, and PHP (referred to under the ELIADC as Active Demand Control Energy Supply Protocol). However, unlike the ELIADC Tariff, the benefits/costs of compliance/non-compliance with the Operating Procedures will flow fully to PHP dependent primarily on PHP operational priorities. As a result, the Operating Procedures are not included as part of the ELID Tariff and not proposed to be subject to NSEB approval.

2.6 Other Applicable Riders

As an ATL customer, PHP will be subject to all Riders applicable to ATL customers in accordance with the individual Rider provisions. Currently, this includes the FAM Rider, Demand Side Management (DSM) Cost Recovery Rider, and Storm Cost Recovery Rider.

2.7 Billing Provisions

In recognition of the large revenue associated with service to PHP, the ELID Tariff retains the ELIADC provisions for weekly billing.

2.8 Tariff Term

As an ATL customer, NS Power will be including PHP in its fuel hedging portfolio. The size of the PHP load is material enough that, should PHP transition to a tariff wherein its load is not included as part of the fuel hedging program it would require an extended period to address the effect of PHP on the hedging program. To address this, the ELID Tariff includes the following term prescribing the minimum notice period required prior to PHP changing to service under another tariff.

> If notice of termination is provided between January 1 and September 30 of the current calendar year, the applicable term shall include the remainder of the current year plus the following calendar year. If notice of termination is provided on or after October 1 of the current calendar year, the applicable term shall include the remainder of the current year plus the next two full calendar years.[6]

2.9 Treatment of Energy Production from the Goose Harbour Lake Wind Farm (PHPW PPA)

The PHP Power Sales Agreement[7] provides:

> **2 SALE AND DELIVERY OF ENERGY**
>
> **2.1 Sale and Delivery of Energy**
>
> (a) Subject to, and in accordance with, the terms and conditions of the Agreement, NSPI shall, in each Contract Year, be obligated to sell and deliver to the Buyer at the Delivery Point, an amount of Energy equal to the aggregate amount of:

[6] Attachment 1, "Term," page 2.
[7] Prescribed under s. 4AA (now s. 24) of the Act.

(i) the Net Output; plus (ii) the difference between the Net Output and the Expected Output for which the Seller under the PHPW PPA was paid or compensated pursuant to either Section 4.2 or Section 4.3 of the PHPW PPA in such Contract Year (the "**Subject Energy Amount**").

(b) In each Contract Year, the Subject Energy Amount shall be sold and delivered to the Buyer Facility before any Tariff Energy supplied by NSPI to the Buyer, and all Energy sold and delivered to the Buyer Facility by NSPI shall be deemed to be supplied hereunder, up to the Subject Energy Amount for such Contract Year, regardless of when the Subject Energy Amount was delivered or deemed to be delivered to NSPI pursuant to the PHPW PPA in such Contract Year.

(c) All Tariff Energy delivered by NSPI to the Buyer in excess of the Subject Energy Amount in any Contract Year shall be subject to the regulated NSPI tariff or tariffs applicable from time to time to Energy supplied by NSPI to the Buyer Facility.

(d) The Subject Energy Amount shall be sold and delivered to the Buyer free of any liens, encumbrances or adverse claims.

(e) The Subject Energy Amount shall be sold to the Buyer without any Renewable Energy Credits or other environmental attributes of any kind.

(f) Load forecasting and scheduling in respect of the Subject Energy Amount shall be conducted in accordance with the NSPI tariff or tariffs applicable from time to time to the Tariff Energy supplied by NSPI to the Buyer Facility in excess of the Subject Energy Amount.[8]

In accordance with this provision, PHP will be billed at the applicable ATL tariff rates for electricity consumed at the PHP facility in excess of the PHPW PPA aggregate amount of: (i) the Net Output; plus (ii) the difference between the Net Output and the Expected Output for which the Seller under the PHPW PPA was paid or compensated pursuant to either Section 4.2 or Section 4.3 of the PHPW PPA, as provided in s. 2.1(a) above. Where the PHPW PPA aggregate amount exceeds PHP consumption in a billing period, the excess PHPW PPA aggregate amount will be carried forward to be applied to PHP consumption in a future billing period.

[8] M12184 – NSPI (IG) IR-1 Attachment 2, page 7 (PDF page 11). May 20, 2025.

NS Power, through the DR service, will continue to seek to optimize the total electricity supplied to PHP (i.e. before the PHPW PPA aggregate amount) and the resultant system savings will be credited to PHP.

2.10 PHP Deferral

The GRA Settlement Agreement provides:

> NS Power may seek Board approval for a deferral account to account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers: (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA; (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.[9]

The GRA incorporates the effect on all ATL classes of PHP served as an ATL customer. The effect of this is that rates for other classes are lower due to the assumed fixed cost recovery included in the forecast embedded cost-based rates applicable to PHP. However, the PHP Deferral recognizes the material variances, both positive and negative, which may arise between assumptions for ATL service to PHP in the GRA and what will actually unfold in the coming months including, but not limited to, the following:

- The cost of service model applicable to NS Power ATL classes;
- The costing and billing determinants applicable to PHP;
- The form of Tariff construct including pricing of the Tariff elements as ultimately approved by the Board;
- As applicable, the form and terms of a Board-approved Dispatchable Rider, Interruptible Rider, and priority interruptible service;

[9] Attachment 4, page 12, item g.

- The timing and energy production from the PHPW PPA during 2026 and 2027;
- PHP consumption over the period 2026 and 2027;
- PHP's agreement to subscribe to the ATL tariff approved by the Board as part of this Application; and
- In the event PHP does not take service under an ATL tariff, the form and financial effect of the alternative.

Following a Board Decision in this matter, the Company will be in a position to identify the differences from the assumptions included in the GRA for ATL service to PHP and the tariff form approved by the Board and understand PHP's plans in relation to taking service under the Board-approved tariff. This will inform the effect of costs and revenues to be included in the PHP Deferral. It is understood that the amounts to be deferred and the timing of recovery of the PHP Deferral will be subject to Board approval.

3.0 COMPARISON OF ELID TARIFF TO ELIADC TARIFF

Within this section, NS Power provides a comparison of the proposed ELID Tariff to the ELIADC Tariff with respect to:

- Consistency with established rate-making practice in Nova Scotia; and
- Benefits to PHP and other ATL customers.

3.1 Consistency with Established Rate-making Practice in Nova Scotia

The proposed ELID Tariff is a fully cost-based tariff. The demand and energy components are embedded cost based. The Customer Charge, the Interruptible Rider,[10] and the Dispatchable Rider credit are incremental cost based. By comparison, the ELIADC Tariff is primarily an incremental

[10] The 2026 and 2027 Interruptible Riders, as proposed, adopt the incremental-cost-based LIIR.

cost-based tariff. The base cost to supply PHP is based on the incremental cost of serving the customer. The Fixed Cost Adder applied to ELIADC Tariff energy sales is not cost-based.

Stakeholder concern with the ELIADC Tariff has included focus on: (1) the calculation/determination of the incremental cost of serving PHP, (2) the perceived unfairness of the Minimum Fixed Cost Recovery (FCR) compared to the FCR embedded in ATL tariffs, and (3) administrative complexity/uncertainty of the pricing construct, in particular, changes to the Customer Baseline and the Tariff price point of $61.75. The design of the ELID Tariff addresses each of these issues in that:

(1) the incremental cost component will be greatly reduced (i.e. limited to the value of the incremental load shift, not the full PHP load) and based on actual load, operations, fuel prices, and system conditions;

(2) subject to agreement on the demand billing/costing determinant in future GRAs and incorporation of the PHPW PPA energy, the demand and energy-related cost of service components will be aligned with other ATL customer costing/pricing; and

(3) the ELID Tariff will not have a Price Point and the CBL will be based on actual results determined at year-end rather than a forecast done in advance of the year.

The ELID Tariff is better aligned with conventional regulatory practice in Nova Scotia and should reduce complexity and controversy amongst stakeholders with respect to NS Power service to PHP. Cost recovery of demand-related costs, in particular, will increase and be more predictable. With respect to the increase in firm service to 8 MW, NS Power has confirmed it has adequate firm supply to accommodate this request in 2026 forward.

3.2 Financial Benefits to ATL Customers

Attachment 2 provides the cost-of-service applicable to PHP using the figures in the SA, including its fuel and non-fuel components and identifies the FCR provided by PHP if served on an ATL tariff for all of 2026 and 2027. This revenue reduces the costs that are borne by all other ATL classes. It is a significant increase over the FCR which has been achieved under the ELIADC Tariff since its inception in 2020.

The reduction in FCR between 2026 and 2027 is due to the reduction in NS Power energy sales to PHP in 2027, as a result of the forecast displacement of NS Power supply with energy production from the PHPW PPA.

In addition to FCR, the ELID Tariff will affect fuel costs borne by other customer classes in two respects:

(1) DR service will reduce total system costs; however, because (as proposed) the benefits of this will accrue to PHP, the net effect on customers will be neutral. Please note, the GRA as filed includes the assumed benefit of the DR service in the fuel budget but does not include compensation due to PHP (i.e. the DR credit). Subject to Board approval of the ELID Tariff, this will be addressed through the FAM.

(2) The incremental cost of serving PHP will affect the total cost of fuel borne by all ATL customers. When marginal costs are below average ATL classes will generally benefit by PHP ATL service at the embedded (i.e. average) cost of fuel. When marginal costs are above average, the reverse applies.

Summary

The ELID Tariff marks an important development in the evolution of service to PHP over the past decade. It builds on processes developed while PHP was served under the predecessor Load Retention Tariff and the ELIADC Tariff and aligns the pricing of service to PHP with the Cost of Service applicable to most of NS Power's retail customers. The ELID Tariff will provide a material and predictable benefit to NS Power's ATL customers.

4.0 CONCLUSION

Development and approval of the Extra Large Industrial Dispatchable Tariff will mark an important milestone in the evolution of service to the province's largest electricity consumer. PHP has progressed from a customer served under a load retention tariff due to economic duress; to having its load integrated to the province's resource portfolio as a demand response resource under the innovative Extra Large Industrial Active Demand Control Tariff; to now the potential that PHP, for the first time, will be served under an embedded cost-based tariff comparable to the service and costing available to other ATL customers, which incorporates the supply of electricity from the PHPW PPA, while retaining the benefit of the flexibility of PHP's load for the benefit of the Customer.

The tariff construct will allow an increased and more predictable contribution by PHP to the fixed costs of the NS Power system to the benefit of other ATL customers and provide PHP with increased electricity price stability. The ELID construct will place control of the actual value realized by PHP load's flexibility in PHP's hands and see the realized value of this tool accrue to the customer creating the value, PHP. Because the benefit will be calculated at year-end based on actual results occurring throughout the year and not a forecast, the foundation for determining the credit will be simpler, more transparent, and less controversial than earlier tariffs.

The ELID Tariff builds on processes and learnings which have been developed by NS Power, PHP, and all stakeholders over the past two decades and, at a time when our regulatory processes appear to be becoming increasingly complex, offers an important opportunity to simplify and improve utility service to the Company's largest customer.

5.0 RELIEF SOUGHT

The Company requests Board Approval of the Extra Large Industrial Dispatchable Tariff as provided in Attachment 1. Considering the development of this Tariff uses well-established costing and pricing processes applicable to the Large Industrial class and adoption of the interruptibility provisions from prior established tariffs, NS Power requests that the Board establish a paper process to consider this Application.

The Extra Large Industrial Dispatchable (ELID) Tariff is an Above-the-Line (ATL) embedded cost-based tariff wherein the Company will dispatch the load of the customer, Port Hawkesbury Paper LP (PHP, the Customer) in a manner to actively manage the Customer's demand in response to system load conditions and reduce the cost to serve the Customer compared to the normally optimal (i.e. high load factor) embedded cost Customer profile, with the resultant savings to accrue to the Customer.

The ELID Tariff Customer Charge will be based on the forecast cost to administer the Tariff as established through the Company's General Rate Applications or other regulatory proceedings, as may be appropriate.

The ELID Tariff Demand and Energy Charges will be based on the Company's embedded cost of service methodology, as established through the Company's General Rate Applications or other regulatory proceedings, as may be appropriate.

The ELID Tariff interruptible service credit(s) will be established through the Company's General Rate Applications or other regulatory proceedings, as may be appropriate.

Applicable Rider Charges will be determined through the normal course of the applicable Rider regulatory proceedings.

The value of the savings created by NS Power's dispatch of the Customer's load, and the corresponding credit to be paid to the Customer, will be calculated at year-end in accordance with the ELID Tariff Dispatchable Rider.

CUSTOMER CHARGE

	per month
Effective January 1, 2026	$10,000
Effective January 1, 2027	$10,000

DEMAND CHARGE

Recognizing that the Customer demand will be determined by the Company and the Customer working collaboratively to actively manage the Customer's demand in response to system load conditions, particularly during peak periods, and to reduce the cost to serve the Customer, the monthly billed per kilovolt ampere (kVA) demand will equal the demand employed in the costing and pricing of the tariff that is approved by the Nova Scotia Energy Board (NSEB, Board). Once established through a General Rate Application, Fuel Adjustment Mechanism (FAM) proceeding, Rider proceeding, etc. or as otherwise directed by the Board, the monthly demand charge will be held constant until revised through a subsequent Board Decision.

	per month
Effective January 1, 2026	$12.872
Effective January 1, 2027	$14.310

ENERGY CHARGE

The following Energy Charge will be applied to all Energy provided to the Customer in excess of any Subject Energy Amount deemed to be provided pursuant to any Sales Agreement issued by the Minister pursuant to Section 4AA of the *Electricity Act*:

	cents per kilowatt-hour
Effective January 1, 2026	9.977
Effective January 1, 2027	11.240

TERM

If notice of termination is provided between January 1 and September 30 of the current calendar year, the applicable term shall include the remainder of the current year plus the following calendar year. If notice of termination is provided on or after October 1 of the current calendar year, the applicable term shall include the remainder of the current year plus the next two full calendar years.

FUEL ADJUSTMENT MECHANISM

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.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the Energy Charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the Energy Charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the monthly Demand Charge and the Customer Charge.

AVAILABILITY

This tariff is applicable to transmission-connected customers having a regular monthly peak metered demand of at least 25,000 kVA. The customer must own the transformation facilities, and no transformer ownership credit is applicable.

PAYMENT FREQUENCY

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days.

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 customer load shall be maintained, or the following adjustment factors (Constant) will be applied to the 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

SPECIAL CONDITIONS

(1) 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% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Should the Customer's requirements make it necessary for NS Power to provide primary metering, the Customer 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 the Customer in connection with service under this Tariff shall be paid for by the Customer as a capital contribution.

(2) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular monthly peak metered demand of at least 25,000 kVA. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 25,000 kVA after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

(3) 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.

(4) 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.

(5) 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.

INTERRUPTIBLE RIDER TO THE ELID TARIFF (RATE CODE X)

The Customer will receive a per month per kilovolt ampere reduction in demand charge for billed interruptible demand as shown in the table below. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is equal to or less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be equal to the interruptible demand used for costing the tariff.

ELID Interruptible Rider Credit	**Reduction per kilovolt ampere reduction in demand charge**
Effective January 1, 2026	$7.638
Effective January 1, 2027	$7.667

Availability

This rider will be applicable to and agreed upon, between the Company and the Customer, under the following terms and conditions:

(1) The Customer has provided written notice of their desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible for the costing and pricing of the tariff.

(2) The Customer will reduce its available interruptible system load by the amount required by NS Power within ten (10) minutes of such request by NS Power. The Customer will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes. 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.

(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 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 NS Power.
- "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.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is 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 in a year.

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.

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 Tariff;
(2) Extra Large Industrial Dispatchable Tariff;
(3) Shore Power Tariff; and
(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.

As compensation for providing this service, the Customer will receive a per month per kilovolt ampere reduction in demand charge for billed interruptible demand as shown in the table below.

ELID Priority Interruptible Credit	**reduction per kilovolt ampere reduction in demand charge**
Effective January 1, 2026	$0.764
Effective January 1, 2027	$0.767

DISPATCHABLE RIDER TO THE ELID TARIFF (RATE CODE X)

Customers taking service under the ELID Tariff will also be subscribed to this Dispatchable Rider (DR). Under this Rider, NS Power will be able to actively manage the Customer's load in accordance with the terms and conditions to be set out in an Operating Procedure developed between NS Power and the Customer. In addition to the Operating Procedure, all of the Availability terms and conditions of the Interruptible Rider shall also apply to all Customer load above the Customer's firm contracted load. The Company shall specifically identify in advance if any of the Customer's load is being interrupted pursuant to the terms and conditions of the Interruptible Rider in accordance with those procedures rather than the Operating Procedure.

The foundation for the process is the assumption that absent subscription to this Rider, the Customer is incented to operate at a high load factor, such that unit costs under the embedded cost-based tariff are minimized. To the extent savings can be created by the customer moving off the high load factor profile to take advantage of lower cost supply periods throughout the year, the resultant savings will accrue to the customer offering the dispatch flexibility, while other customers are held harmless.

The savings created by NS Power dispatch of the Customer load (DR credit) will be calculated at year-end by comparing the actual system costs with the Customer's actual dispatched load to a scenario where the actual Customer load is replaced by the high load factor customer profile (i.e. the Customer Baseline (CBL)) which incorporates actual Customer load, the dates and durations of the Customer's major scheduled maintenance periods and other factors as may be appropriate to calculate a representative CBL.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through the dispatch of the Customer's load under the Operating Procedure. NS Power shall endeavour to submit this report no later than 60 days after the end of a tariff year. The Customer will be entitled to a credit equal to the cost differential between the actual annual system cost and the calculated system cost if the Customer was served under the high load factor scenario.

Extra Large Industrial Dispatchable Tariff Application, Attachment 2 has been filed electronically.

Customer Charge Estimates for Extra Large Industrial Dispatchable Tariff

Task Required to Support the Tariff	Cost Estimate			
	Approx. Cost per Month		Approx. Cost per Year	
	low range	high range	low range	high range
Development, management, and refinement of Operating Procedures	417	417	5,000	5,000
Engagement with PHP on development of PHP dispatch schedule	417	833	5,000	10,000
System Operator engagement with PHP on dispatch	417	833	5,000	10,000
Regulatory engagement and reporting and ad-hoc customer requests	417	417	5,000	5,000
Engagement with PHP on development of forecast and actual Dispatchable Rider (DR) benefit	2,083	2,917	25,000	35,000
Periodic PLEXOS and PortOps modeling and report preparation.	2,500	4,167	30,000	50,000
Real-time optimization of PHP load to achieve the most economic system dispatch	2,917	3,750	35,000	45,000
Providing dispatch instructions to PHP based on economic dispatch optimization results and real-time system conditions	833	1,250	10,000	15,000
Total	**$ 10,000.00**	**$ 14,583.33**	**$ 120,000.00**	**$ 175,000.00**

Nova Scotia Energy Board

IN THE MATTER OF A GENERAL RATE APPLICATION by NOVA SCOTIA POWER INCORPORATED for approval of certain revisions to its Rates, Charges, and Regulations

Settlement Agreement

WHEREAS

A. Nova Scotia Power ("NS Power"), along with the Consumer Advocate ("CA"), Small Business Advocate ("SBA"), counsel for the Industrial Group, representing CKF Inc., Crown Fibre Tube Inc., Irving Shipbuilding Inc., K + S Windsor Salt Ltd., Maritime Paper Products Ltd., Michelin North America (Canada) Inc., Compass Minerals Canada Corp., Farnell Packaging Ltd., P & H Milling Group, and PSA Halifax ("IG"), counsel for the Berwick Electric Commission, Riverport Electric Light Commission, the Town of Mahone Bay, and the Town of Antigonish (Municipal Electric Utilities or "MEUs"), and counsel for Port Hawkesbury Paper ("PHP") (collectively, the "Customer Representatives", who along with NS Power are referred to herein as the "Parties") have engaged in a collaborative process to reach consensus on a 2026-2027 General Rate Application ("GRA").

B. This collaborative process included multiple meetings and the sharing of information that led to NS Power providing the Customer Representatives with a proposed 2026-2027 GRA on April 25, 2025 ("Draft GRA").

C. On May 27, 2025, Customer Representatives were then provided with all Draft GRA supporting documentation, including standardized filings.

D. Following the provision of these materials, the Parties participated in two rounds of information requests, multiple technical conferences, and three full days of settlement meetings.

E. Throughout the process described in the foregoing, Customer Representatives were aided by their respective expert consultants, as each deemed necessary or appropriate.

F. The Parties desire to resolve the 2026-2027 GRA on the terms set out herein.

NOW THEREFORE, the Parties agree as follows:

1. The Parties have reached agreement on the outcomes that will result from the 2026-2027 GRA as represented by the terms set out in Schedule “A” attached hereto (“Settlement Agreement”). The Parties acknowledge NS Power will be filing its 2026-2027 GRA in all other respects consistent with the Draft GRA.

2. NS Power will file the 2026-2027 GRA with the Nova Scotia Energy Board (“Board” or “NSEB”) in a manner consistent with this Settlement Agreement. The Customer Representatives reserve the right to ask Information Requests and file evidence in the event the filed 2026-2027 GRA application is inconsistent with this Settlement Agreement.

3. Prior to filing the 2026-2027 GRA with the Board, NS Power will file a letter with the Board, notifying it of the forthcoming 2026-2027 GRA. The letter will include an overview of the collaborative process that the Parties have undertaken and a mutually agreed-upon expression of their support for the outcomes of the 2026-2027 GRA (“Pre-GRA Letter”).

4. The 2026-2027 GRA will include an overview of the collaborative process that the Parties have undertaken and a mutually agreed-upon expression of their support for the outcomes of the 2026-2027 GRA. If requested by the Board, the Customer Representatives will also provide their own written expression of their support for the outcomes of the 2026-2027 GRA.

5. The Parties understand that time is of the essence, and they will use reasonable efforts to facilitate the filing of both the Pre-GRA Letter and the 2026-2027 GRA in a timely manner.

6. The Parties agree to the terms set out in Schedule “A” to resolve the matters at issue for the 2026-2027 GRA and without prejudice to any position that may be taken by any Party in any future regulatory proceeding.

7. This Settlement Agreement may be executed by the Parties in counterparts, each of which when so executed and delivered shall be deemed to be an original and when taken together shall be deemed to be one and the same instrument. The electronic delivery, including, without limitation, by email, of any signed original of this Settlement Agreement shall be the same as the delivery of an original.

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE

Per: David Roberts and Michael Murphy

SMALL BUSINESS ADVOCATE

Per:

INDUSTRIAL GROUP

Per:

NOVA SCOTIA POWER INC.

Per:

PORT HAWKESBURY PAPER LP

Per:

MUNICIPAL ELECTRIC UTILITIES

Per:

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE	**SMALL BUSINESS ADVOCATE**
______________________	Melissa Mac
Per:	**Per:** MELISSA P. MACADAM
INDUSTRIAL GROUP	**NOVA SCOTIA POWER INC.**
______________________	______________________
Per:	**Per:**
PORT HAWKESBURY PAPER LP	**MUNICIPAL ELECTRIC UTILITIES**
______________________	______________________
Per:	**Per:**

All of which is hereby agreed to by the Parties effective as of the 29th day of August, 2025.

CONSUMER ADVOCATE

Per:

SMALL BUSINESS ADVOCATE

Per:

INDUSTRIAL GROUP

Per: Nancy G. Rubin, K.C.

NOVA SCOTIA POWER INC.

Per:

PORT HAWKESBURY PAPER LP

Per:

MUNICIPAL ELECTRIC UTILITIES

Per:

All of which is hereby agreed to by the Parties effective as of the ____ day of August, 2025.

CONSUMER ADVOCATE

____

Per:

SMALL BUSINESS ADVOCATE

____

Per:

INDUSTRIAL GROUP

____

Per:

NOVA SCOTIA POWER INC.

____

Per: Peter Gregg
President and CEO

PORT HAWKESBURY PAPER LP

____

Per:

MUNICIPAL ELECTRIC UTILITIES

____

Per:

2026-2027 General Rate Application Settlement Agreement

All of which is hereby agreed to by the Parties effective as of the 29 day of August, 2025.

CONSUMER ADVOCATE

Per:

SMALL BUSINESS ADVOCATE

Per:

INDUSTRIAL GROUP

Per:

NOVA SCOTIA POWER INC.

Per:

PORT HAWKESBURY PAPER LP

Bevan Lock

Per: Bevan Lock

MUNICIPAL ELECTRIC UTILITIES

Per:

2026-2027 General Rate Application Settlement Agreement

All of which is hereby agreed to by the Parties effective as of the 29th day of August, 2025.

CONSUMER ADVOCATE	**SMALL BUSINESS ADVOCATE**
______________________	______________________
Per:	**Per:**
INDUSTRIAL GROUP	**NOVA SCOTIA POWER INC.**
______________________	______________________
Per:	**Per:**
PORT HAWKESBURY PAPER LP	**MUNICIPAL ELECTRIC UTILITIES**
______________________	______________________
Per:	**Per:** James MacDuff

Schedule "A"

Terms of Settlement

It is acknowledged that, subject to Board approvals, rate increases other than those identified herein may occur prior to the effective date of the next general rate application in the form of Board-approved riders. Recognizing the forecast impacts of the 2026 FAM AA/BA for the Large and Medium Industrial Classes, NS Power will support efforts in the 2026 FAM AA/BA proceeding to smooth or mitigate the overall impact of rate changes for the 2026-2027 test period.

GRA Element	Settlement Terms
Rates	a) Rates are proposed to be effective January 1, 2026 and the Parties will make all reasonable efforts to facilitate and support a process that will result in this outcome. b) Subject to the terms set out herein being fully incorporated into the 2026-2027 GRA, the average rate increase across all customer classes (inclusive of non-fuel and Base Cost of Fuel costs) is anticipated to be approximately 2.1% in 2026 and 2.1% in 2027.
Depreciation	a) The Parties agree to reduce depreciation rates in accordance with Appendix "A" in order to achieve a reduction in depreciation and accretion expense of approximately $20M/year over the 2026-2027 test period, as compared to the depreciation rates included in the Draft GRA.
O&M	a) The Parties agree to the operation and maintenance expense amounts included in the Draft GRA, subject to the reductions in O&M set out in the attached Appendix "B".
Storm Cost Recovery Rider	a) The Storm Cost Recovery Rider will be implemented as described in the Draft GRA, subject to the following: (a) the Storm Cost Recovery Rider will not be implemented on a permanent basis as proposed, rather it will continue on a pilot basis with costs in 2026 and 2027 eligible for the rider; and (b) the threshold for making an application to return an

GRA Element	Settlement Terms
	underspend to customers will be changed from $5 million to $2.5 million.
Cost of Capital and Earnings Band	a) An overall return on equity of 9% for rate setting purposes retained, as well as an earnings band of 8.75% to 9.25%.
Capital Structure	a) An equity thickness of 40% for rate setting purposes will be retained.
DSM Rider	a) The DSM Rider will be amended as set out in Appendix "C". NS Power will make best efforts to negotiate necessary revisions to its Supply Agreement with EfficiencyOne, if any, or otherwise bring such revisions forward in the relevant proceeding to ensure that the End of Approved DSM Term Adjustment is implemented for the 2023-2026 term.
Weather Normalization Mechanism	a) The request for approval of a Weather Normalization Mechanism will be removed; however, the parties agree to participate in an information session to gain a better understanding of Weather Normalization Mechanisms.
Cost of Service ("COS")	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.
MEU Treatment	a) The MEUs will be included as taking service under the Municipal Tariff in calculating the Municipal Tariff rates for the 2026-2027 GRA and the MEUs commit to taking partial service under the Municipal Tariff in the years 2026 and 2027 .

GRA Element	Settlement Terms
	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.
OATT	a) In calculating the OATT rate, NS Power will cap the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service. b) The 2-standard deviation methodology will be used for ratemaking purposes for the load following requirement. c) For the 2026-2027 GRA period, the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis.
PHP Treatment	a) NS Power's 2026/2027 cost of service study includes PHP as an above-the-line customer based on the forecast of receiving Board approvals for a new PHP tariff in time to implement for January 1, 2026. b) The COS has been prepared on the basis of the following PHP load characteristics: a) PHP's firm load at 8MW at the three coincident peaks; b) PHP's firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP metered load at the time of NSP's 3CP; and c) PHP energy will be based on PHP's forecast usage for the test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm. The same load characteristics are applicable to the base cost of fuel model as well. c) The dollar value of the Interruptible credit to be applicable to PHP's interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit. d) PHP and NS Power will complete discussions and analysis of the value of Active Demand Control ("ADC"), which shall be proposed to be a rider to the cost-based rate. The value of ADC, and the proposal for cost recovery, if any, shall be

GRA Element	Settlement Terms
	brought forward for approval by the Board later this year to be effective January 1, 2026. For clarity, any payment approved by the Board for Active Demand Control services will be collected from above the line customers. e) NS Power and PHP shall reflect the foregoing in a written tariff which shall also include a proposal for priority interruptibility to be brought forward for approval by the Board later this year to be effective January 1, 2026 and PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes. f) In the PHP ADC and tariff processes that will be brought forward for approval by the Board later this year, it remains open for all Parties to take any position they so choose, including whether each of the PHP ADC and tariff filing(s) is inconsistent with the load characteristics and basic tariff structure as set out above. g) NS Power may seek Board approval for a deferral account to account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers: (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA; (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.
Securitization	a) NS Power will make best efforts to finalize and apply prior to January 1, 2026 for approval of its proposed securitization of assets, cost of service treatment and the Securitization Rider. It remains open for all Parties to take any position they so choose in relation to such an application.
ML Transmission Assets	a) Inclusion of CI 43324, CI 43678, CI 45066, and CI 45067 in rate base, subject to the Board being satisfied that the threshold test it articulated in paragraph 405 of its decision in M10431 has been met.

GRA Element	Settlement Terms
EIFEL	a) If the excessive interest and financing expenses limitation ("EIFEL") exemption is not enacted, the Parties agree to defer the incremental tax expense over the 2026-2027 GRA period, which is anticipated to be approximately $7.5 million.
NS Power Future Deliverables	a) Within a reasonable amount of time following the execution of this Settlement Agreement, NS Power will provide: (a) confirmation that radial to generation lines being allocated to the generation function do not also serve any load; and (b) the methodology that NS Power is proposing to functionalize storage assets.

Appendix "A"

Appendix "A"

NOVA SCOTIA POWER, INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP (1)	PROBABLE RETIREMENT DATE (2)	ESTIMATED SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2023 (5)	BOOK RESERVE AS OF DECEMBER 31, 2023 (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
	DEPRECIABLE PLANT									
310.99	**STEAM PRODUCTION PLANT**									
	LINGAN									
	LINGAN 1	12-2049	65 - L1 a	(10)	138,151,529	103,751,275	48,215,407	2,234,591	1.62	21.6
	LINGAN 2	12-2029	65 - L1 a	(10)	86,836,521	100,062,274	(4,542,101)	-	-	-
	LINGAN 3-4	12-2049	65 - L1 a	(10)	290,616,704	171,721,364	147,957,010	7,037,590	2.42	21.0
	LINGAN - COMMON	12-2049	65 - L1 a	(10)	137,819,664	31,467,217	120,134,413	5,459,756	3.96	22.0
	TOTAL LINGAN				*653,424,418*	*407,002,131*	*311,764,729*	*14,731,937*	*2.25*	
	POINT ACONI	12-2029	65 - L1 a	(5)	574,355,237	243,710,224	359,362,775	62,112,977	10.81	5.8
	POINT TUPPER	12-2048	65 - L1 a	(8)	204,646,401	93,394,889	127,623,224	6,198,266	3.03	20.6
	TRENTON									
	TRENTON 5	12-2029	65 - L1 a	(4)	154,246,212	69,420,216	90,995,844	15,520,279	10.06	5.9
	TRENTON 6	12-2029	65 - L1 a	(4)	287,095,316	131,910,745	166,668,384	29,020,962	10.11	5.7
	TRENTON - COMMON	12-2029	65 - L1 a	(4)	68,919,523	11,056,285	60,620,018	10,263,264	14.89	5.9
	TOTAL TRENTON				*510,261,050*	*212,387,246*	*318,284,246*	*54,804,505*	*10.74*	
	TUFTS COVE									
	TUFTS COVE 1	12-2049	65 - L1 a	(5)	51,886,821	32,885,132	21,596,030	969,279	1.87	22.3
	TUFTS COVE 2	12-2049	65 - L1 a	(5)	58,767,019	26,896,529	34,808,842	1,578,906	2.69	22.0
	TUFTS COVE 3	12-2049	65 - L1 a	(5)	90,099,433	40,234,912	54,369,492	2,508,142	2.78	21.7
	TUFTS COVE 6	12-2049	65 - L1 a	(5)	99,805,461	34,254,208	70,541,526	3,193,342	3.20	22.1
	TUFTS COVE - COMMON	12-2049	65 - L1 a	(5)	102,844,873	39,733,086	68,254,030	3,134,100	3.05	21.8
	TOTAL TUFTS COVE				*403,403,606*	*174,003,866*	*249,569,920*	*11,383,769*	*2.82*	
	POINT TUPPER MARINE TERMINAL	12-2029	100 - R1 a	(15)	35,156,805	18,934,839	21,495,487	3,618,881	10.29	5.9
	PORT HAWKESBURY BIOMASS	12-2045	65 - L1 a	(4)	212,173,030	40,969,204	179,690,747	9,220,034	4.35	19.5
	INTERNATIONAL COAL PIER	12-2029	65 - L1 a	(154)	11,628,782	(5,594,604)	35,131,711	5,930,262	51.00	5.9
	GENERAL	12-2029			11,918,057	4,607,622	7,310,434	1,218,406	10.22	6.0
	TOTAL STEAM PRODUCTION PLANT				**2,616,967,386**	**1,189,415,417**	**1,610,233,273**	**169,219,037**	**6.47**	
330.99	**HYDRAULIC PRODUCTION PLANT**									
	AVON	12-2066	100 - L0.5 a	(13)	19,190,750	7,374,478	14,311,070	418,280	2.18	34.2
	BEAR RIVER	12-2066	100 - L0.5 a	(15)	62,888,372	13,223,548	59,098,081	1,735,627	2.76	34.0
	BLACK RIVER	12-2066	100 - L0.5 a	(12)	56,119,196	12,773,630	50,079,869	1,465,503	2.61	34.2
	DICKIE BROOK	12-2066	100 - L0.5 a	(6)	16,019,562	1,175,021	15,805,714	460,490	2.87	34.3
	FALL RIVER	12-2066	100 - L0.5 a	(24)	2,433,707	440,846	2,576,950	75,314	3.09	34.2
	LEQUILLE	12-2066	100 - L0.5 a	(10)	42,258,224	5,550,380	40,933,667	1,198,840	2.84	34.1
	ST. MARGARETS	12-2066	100 - L0.5 a	(5)	52,563,783	13,049,922	42,142,051	1,218,918	2.32	34.6
	SHEET HARBOUR	12-2066	100 - L0.5 a	(8)	33,492,534	9,153,795	27,018,142	797,225	2.38	33.9
	TUSKET		100 - L0.5	(20)	23,001,092	5,585,327	22,015,983	400,170	1.74	55.0
	WRECK COVE		100 - L0.5	(20)	241,849,833	80,739,861	209,479,939	3,964,699	1.64	52.8
	MERSEY		100 - L0.5	(20)	40,259,998	20,874,637	27,437,361	567,195	1.41	48.4
	GENERAL				23,944,861	(2,085,374)	26,030,235	499,216	2.08	
	TOTAL HYDRAULIC PRODUCTION PLANT				**614,021,913**	**167,856,071**	**536,929,062**	**12,801,477**	**2.08**	
340.96	**SOLAR PRODUCTION PLANT**									
	SOLAR SMARTGRID	12-2051	45 - R2.5 a	0	1,582,854	98,009	1,484,845	61,606	3.89	24.1
	TOTAL SOLAR PRODUCTION PLANT				**1,582,854**	**98,009**	**1,484,845**	**61,606**	**3.89**	
340.99	**OTHER PRODUCTION PLANT**									
	OTHER PRODUCTION - GAS TURBINES									
	BURNSIDE	12-2049	75 - S0.5 a	(3)	43,645,266	14,071,208	30,883,416	1,309,193	3.00	23.6
	TUSKET	12-2049	75 - S0.5 a	(1)	17,461,600	6,878,555	10,757,661	448,016	2.57	24.0
	VICTORIA JUNCTION	12-2049	75 - S0.5 a	(6)	20,230,710	7,604,683	13,839,869	577,509	2.85	24.0
	TUFTS COVE									
	TUFTS COVE CT UNIT 4	12-2049	30 - L0.5 a	(11)	57,829,237	11,119,148	53,071,305	3,829,244	6.62	13.9
	TUFTS COVE CT UNIT 5	12-2049	30 - L0.5 a	(11)	39,322,118	3,328,106	40,319,444	2,870,636	7.30	14.0
	TOTAL TUFTS COVE				97,151,355	14,447,255	93,390,749	6,699,880	6.63	13.9
	TOTAL OTHER PRODUCTION - GAS TURBINES				178,488,931	43,001,701	148,871,695	9,034,598	5.06	
	OTHER PRODUCTION - WIND									
	DIGBY	12-2036	90 - S0.5 a	(2)	67,721,102	30,355,934	38,719,590	3,047,396	4.50	12.7
	NUTTBY	12-2035	90 - S0.5 a	(2)	111,163,131	59,566,442	53,819,951	4,580,296	4.12	11.8
	CANSO/SABLE	12-2039	90 - S0.5 a	(2)	12,399,704	4,488,546	8,159,151	526,382	4.25	15.5
	SOUTH CANOE	12-2040	90 - S0.5 a	(1)	98,031,286	33,630,847	65,380,751	3,962,466	4.04	16.5
	TUPPER/BEARHEAD	12-2035	90 - S0.5 a	(2)	24,785,573	13,165,184	12,116,101	1,031,094	4.16	11.8
	TOTAL OTHER PRODUCTION - WIND				314,100,795	141,206,954	178,195,544	13,147,634	4.19	
	TOTAL OTHER PRODUCTION PLANT				**492,589,726**	**184,208,655**	**327,067,239**	**22,182,232**	**4.50**	
	TRANSMISSION PLANT									
350.10	LAND RIGHTS - EASEMENTS		80 - R5	0	100,622,597	26,905,421	73,717,175	1,330,578	1.32	55.4
353.00	STATION EQUIPMENT		48 - R2.5	(20)	586,908,962	253,049,476	451,241,279	16,060,367	2.74	28.1
354.00	TOWERS AND FIXTURES		60 - S2.5	(20)	111,028,870	73,423,125	59,811,519	1,449,994	1.31	41.2
355.00	POLES AND FIXTURES		45 - R1.5	(20)	268,176,042	82,589,384	239,221,867	9,209,997	3.43	26.0
356.00	OVERHEAD CONDUCTORS AND DEVICES		45 - R3	(20)	178,454,463	75,534,094	138,611,261	5,546,910	3.11	25.0
357.00	UNDERGROUND CONDUIT		65 - S3	0	1,736,139	611,263	1,124,876	27,127	1.56	41.5
358.00	UNDERGROUND CONDUCTORS AND DEVICES		45 - S3	(10)	7,345,546	853,459	7,226,642	194,359	2.65	37.2
359.00	ROADS, TRAILS AND BRIDGES		60 - S3	0	344,183	110,123	234,060	6,260	1.82	37.4
	TOTAL TRANSMISSION PLANT				**1,254,616,801**	**513,076,344**	**971,188,679**	**33,825,592**	**2.70**	
	DISTRIBUTION PLANT									
360.10	LAND RIGHTS - EASEMENTS, SURVEYS AND CLEARING		65 - R5	0	118,136,716	15,711,852	102,424,864	1,860,352	1.57	55.1
361.00	STRUCTURES AND IMPROVEMENTS		55 - R3	(5)	2,418,694	750,104	1,789,525	40,916	1.69	43.7
362.00	STATION EQUIPMENT		55 - R1.5	(5)	74,535,144	64,521,947	13,739,954	501,585	0.67	27.4
362.10	SCADA EQUIPMENT		15 - S2.5	(5)	473,094	475,824	20,924	1,774	0.37	11.8
362.20	REMOTE MONITORING EQUIPMENT		15 - S2.5	(5)	393,349	388,219	24,797	2,108	0.54	11.8
362.30	STATION EQUIPMENT - MISCELLANEOUS		15 - S2.5	(5)	13,123,052	11,030,074	2,749,130	236,947	1.81	11.6
363.10	ENERGY STORAGE EQUIPMENT - EV CHARGERS		15 - S3	0	987,094	158,436	828,658	71,330	7.23	11.6
363.20	ENERGY STORAGE EQUIPMENT - DISTRIBUTED SOLAR		25 - S3	0	1,123,202	64,625	1,058,577	48,536	4.32	21.8
363.30	ENERGY STORAGE EQUIPMENT - BATTERIES		10 - S3	0	1,261,438	201,460	1,059,978	141,434	11.21	7.5
364.00	POLES, TOWERS AND FIXTURES		43 - R2	(35)	646,990,061	406,226,456	467,210,126	18,024,106	2.79	25.9
365.00	OVERHEAD CONDUCTORS AND DEVICES		42 - R2	(26)	329,509,672	144,738,996	270,443,190	11,067,585	3.36	24.4
366.00	UNDERGROUND CONDUIT		70 - S3	0	8,554,638	4,309,841	4,244,798	105,112	1.23	40.4
367.00	UNDERGROUND CONDUCTORS AND DEVICES		42 - R3	(25)	75,012,364	33,657,017	60,108,439	2,407,126	3.21	25.0
368.00	LINE TRANSFORMERS		35 - R1	(25)	555,455,934	237,671,905	456,648,012	23,885,113	4.30	19.1
369.00	SERVICES		48 - S2.5	(65)	149,613,065	134,202,103	112,659,454	3,885,448	2.60	29.0
370.00	METERS		20 - S2	(10)	6,155,844	6,077,871	693,557	40,535	0.66	17.1
370.10	METERS - AMI		18 - S2	(10)	96,761,787	18,747,008	87,690,959	7,299,539	7.54	12.0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		22 - R2.5	(15)	19,074,061	12,890,306	9,044,865	839,992	4.40	10.8
373.10	STREET LIGHTING AND SIGNAL SYSTEMS - LED		20 - S2	(15)	38,107,176	15,677,772	28,145,481	3,257,814	8.55	8.6
	TOTAL DISTRIBUTION PLANT				**2,137,686,386**	**1,107,501,816**	**1,620,585,288**	**73,717,352**	**3.45**	
	GENERAL PLANT									
389.10	LAND RIGHTS - GENERAL PLANT		50 - R5	0	4,346,529	1,595,626	2,750,903	77,009	1.77	35.7
390.10	STRUCTURES AND IMPROVEMENTS		43 - R3	(10)	184,609,960	73,153,643	129,917,313	5,001,545	2.71	26.0
391.10	OFFICE FURNITURE AND EQUIPMENT		20 - SQ	0	2,218,574	1,108,351	1,110,223	110,705	5.00	10.0
	RESERVE VARIANCE AMORT - OFFICE FURNITURE AND EQUIPMENT					919,412 c	(919,412)	(183,882)		5.0 b
391.31	OFFICE FURNITURE AND EQUIPMENT - COMPUTER HARDWARE		5 - SQ	0	27,846,698	9,640,416	18,206,282	5,360,624	20.00	3.4
	RESERVE VARIANCE AMORT - COMPUTER HARDWARE					(416,440) c	416,440	83,288		5.0 b
391.32	OFFICE FURNITURE EQUIPMENT - COMPUTER SOFTWARE		10 - SQ	0	246,257,554	85,873,932	160,383,622	24,625,754	10.00	6.5
	RESERVE VARIANCE AMORT - COMPUTER SOFTWARE					(22,338,881) c	22,338,881	4,467,776		5.0 b
392.00	TRANSPORTATION EQUIPMENT		13 - R1	10	102,651,502	53,324,459	39,061,892	5,179,062	5.05	7.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	0	3,986,623	1,103,512	2,883,111	199,331	5.00	14.5
	RESERVE VARIANCE AMORT - TOOLS, SHOP AND GARAGE EQUIPMENT					(180,288) c	180,288	36,058		5.0 b
397.00	COMMUNICATION EQUIPMENT		22 - R2.5	(5)	91,516,693	49,199,545	46,892,983	3,164,612	3.46	14.8
397.10	COMMUNICATION EQUIPMENT - SCADA EQUIPMENT		19 - R2	(5)	28,577,987	10,319,624	19,687,262	2,863,731	10.02	6.9
397.20	REMOTE MONITORING EQUIPMENT		15 R3	0	3,488,768	2,207,852	1,280,916	117,761	3.38	10.9
398.00	MISCELLANEOUS EQUIPMENT		20 - SQ	0	42,982,053	22,611,639	20,370,414	2,122,241	5.00	9.6
	RESERVE VARIANCE AMORT - MISCELLANEOUS EQUIPMENT					(3,178,537) c	3,178,537	635,707		5.0 b
399.76	MISCELLANEOUS EQUIPMENT (KELLY ROCK)	12-2029	40 - R2	(5)	2,513,071	2,489,646	149,078	26,380	1.05	5.7
	TOTAL GENERAL PLANT				**740,996,013**	**287,433,514**	**467,888,732**	**53,887,702**	**7.27**	
	FULLY AMORTIZED GENERAL PLANT [d]									
391.10	OFFICE FURNITURE AND EQUIPMENT				7,251,565	7,251,565				
391.31	OFFICE FURNITURE AND EQUIPMENT - COMPUTER HARDWARE				29,762,603	29,762,603				
391.32	OFFICE FURNITURE AND EQUIPMENT - COMPUTER SOFTWARE				18,345,792	18,345,792				
393.00	STORES EQUIPMENT				472,905	472,905				
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT				7,560,490	7,560,490				
395.00	LABORATORY EQUIPMENT				2,684,879	2,684,879				
398.00	MISCELLANEOUS EQUIPMENT				1,320,249	1,320,249				
	TOTAL FULLY AMORTIZED GENERAL PLANT				**67,398,483**	**67,398,483**				
	TOTAL DEPRECIABLE PLANT STUDIED				**7,925,859,562**	**3,516,988,310**	**5,535,377,118**	**365,694,997**	**4.61**	
	DEPRECIABLE PLANT NOT STUDIED									
	THERMAL PRODUCTION PLANT NOT STUDIED									
	GLACE BAY				-	72,934				
	WATER STREET				-	-				
	TOTAL STEAM PRODUCTION PLANT NOT STUDIED				-	72,934				
	HYDRAULIC PRODUCTION PLANT NOT STUDIED									
	ANNAPOLIS TIDAL				39,271,385	16,930,661				
	HARMONY (RETIRED)				-	15,635				
	ROSEWAY (RETIRED)				-	(1,223,840)				
	TOTAL HYDRAULIC PRODUCTION PLANT NOT STUDIED				39,271,385	15,722,456				
	WIND PRODUCTION PLANT NOT STUDIED									
	GRAND ETANG (RETIRED)				6,196	6,197				
	TOTAL WIND PRODUCTION PLANT NOT STUDIED				6,196	6,197				
	ARO COSTS				(12,291,457)	(19,119,247)				
	CAPITAL CONTRIBUTIONS				(155,427,722)	(154,748,262)				
	SITE RESTORATION ASSET				-	-				
	TOTAL DEPRECIABLE PLANT NOT STUDIED				**(128,441,598)**	**(158,065,921)**	**-**	**-**		
	TOTAL DEPRECIABLE PLANT				**7,797,417,965**	**3,358,922,389**	**5,535,377,118**	**365,694,997**		
	NONDEPRECIABLE PLANT									
	PURCHASE DIFFERENCE				2,334,555	-				
	NON-UTILITY PROPERTY				14,641,746	4,405,697				
	RESEARCH AND DEVELOPMENT				-	-				
	LAND - STEAM PRODUCTION				5,121,213	-				
	LAND - HYDRAULIC PRODUCTION				5,396,781	-				
	LAND - WIND PRODUCTION				39,000	-				
	LAND - OTHER PRODUCTION				7,629	-				
	LAND - TRANSMISSION				13,274,264	-				
	LAND - DISTRIBUTION				4,563,115	-				
	LAND - GENERAL				12,033,064	340,495				
	TOTAL NONDEPRECIABLE PLANT				**57,411,367**	**4,746,191**	**-**	**-**		
	TOTAL ELECTRIC PLANT				**7,854,829,331**	**3,363,668,580**	**5,535,377,118**	**365,694,997**		

Footnotes:

a Curve shown represents interim survivor curve.

b Special reserve variance amortization adjustment proposed. The reserve variance related to computer hardware will be amortized over a 5 year period rather than the account's remaining life.

c Amount shown represents the reserve variance related to computer hardware and software. The reserve variance is the difference between the theoretical reserve and the book reserve.

d Amounts shown are for vintages outside of the amortization period for each account. These amounts should be retired with the adoption of amortization accounting.

Appendix "B"

Reduced OM&G	**2026**	**2027**
Energy Delivery	5,000,000	5,000,000
Customer Experience	2,000,000	2,000,000
Corporate	2,000,000	2,000,000
Total OM&G Reduction	**9,000,000**	**9,000,000**
Reduced Regulatory Amortization (GRA Deferral)	**1,000,000**	**1,000,000**
Total Reduced OM&G and Regulatory Amortization	**10,000,000**	**10,000,000**

Appendix "C"

Attached as a separate document starting on the next page.

APPLICABILITY

This schedule applies to all electric rate classes with the exception of the Wholesale Market Non-Dispatchable Supplier Spill Tariff, the Load Retention Tariff, and the Extra Large Industrial Active Demand Control Tariff. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of the costs of electricity efficiency and conservation activities, as defined in Section 79A of the Public Utilities Act (Demand Side Management or DSM) approved by the Nova Scotia Energy~~Utility and Review~~ Board (NS~~UAR~~EB) will be direct billed in accordance with the customer's class energy bill as if served by Nova Scotia Power Incorporated (NS Power) under its bundled service offerings.

RESPONSIBILITIES OF FRANCHISE HOLDER

It is the responsibility of the holder of the electric efficiency and conservation franchise granted under Section 79C of the Public Utilities Act (Franchise Holder) to apply to the Nova Scotia ~~Utility and Review Board (~~NS~~UAR~~EB~~)~~ to seek approval of all DSM activities, plans and programs, and to itemize and seek approval for all related costs.

On or before October 1 in the year preceding the implementation of the approved programs, NS Power shall apply to the NS~~UAR~~EB to seek approval of the DSM Cost Recovery Rider amounts to be inserted in Schedule A to this tariff for the succeeding rate year. NS Power shall pay to the Franchise Holder the amount approved by the NS~~UAR~~EB to fund the DSM costs, on a monthly basis.

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR)

The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Rider is applicable shall be increased or decreased by the DCRR at a class-specific rate per kilowatt hour of consumption in accordance with the following formula:

DCRR = PCR + BA

Where:

PCR = Program Cost Recovery

The PCR includes all estimated costs for the upcoming calendar year for the DSM Plan that has been requested by the Franchise Holder and approved by the NS~~UAR~~EB (Approved DSM). It includes the cost of planning, developing, implementing, monitoring, evaluating, and verifying DSM programs, and includes but is not limited to costs for enabling strategies, consultants, employees, and administrative expenses. The PCR is computed for each rate schedule using the cost allocation methodology set out in Schedule B to this tariff.

BA = Balance Adjustment

The BA is comprised of two components:

(1) BA_1 = Annual Volume Variance Adjustment – ~~is~~ calculated for each rate class separately on a previously completed calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the PCR and the revenues which should have been billed based on actual class load in the previously completed calendar year.~~, as follows:~~ In order to enable incorporation of a full year's actual results, the BA_1 is applied on a two-year lag and ~~will~~ addresses differences in the year that occurred 2 years prior to the current PCR year~~[1]~~.

~~(1)~~(2) BA_2 = End of Approved DSM Term Adjustment – reconciles~~The balance adjustment amount is~~ the difference between the Approved DSM amount billed in the previously completed ~~calendar year from the application of the PCR unit charges~~ Approved DSM Term[2] and the actual ~~cost of the~~ Approved DSM expenditures incurred by the Franchise Holder during the same previously completed ~~calendar year~~Approved DSM Term. Following the conclusion of the Approved DSM Term, the BA_2 is calculated by customer class based on actual spending and is applied over the remainder of the succeeding Approved DSM Term[3]. This adjustment ensures that customers are charged or refunded based on actual DSM program expenditures in their respective class.

Total BA = $BA_1 + BA_2$

The BA shall be updated annually to reflect BA_1, and at the conclusion of each Approved DSM Term to reflect BA_2. The NS~~UAR~~EB-approved DCRR shall be placed into effect with bills rendered on and after the effective date of such change.

SCHEDULE A

2025 DSM Cost Recovery Rider Charges

The Demand Side Management Cost Recovery Rider (DCRR) charges, along with its components, (PCR) and (BA), for the period from the approved effective date of January 1, 2025 to December 31, 2025 are as follows:

~~[1] Balance Adjustment for 2023 will come into effect on January 1, 2025 and will be based on the revenue collected between February 2, 2023, and December 31, 2023. The revenue will be compared to the DSM costs incurred in that same period.~~

[2] The Approved DSM Term refers to the full DSM Plan period in effect (e.g. 2023-2026, 2027-2031).

[3] For example, following the conclusion of the 2023-2026 term, the BA_2 is calculated (in 2027) and is applied equally, on a per year basis, over the remainder of the 2027-2031 term (e.g. four years – 2028, 2029, 2030, and 2031).

Applicable Tariff	PCR (cents per kWh)	BA (cents per kWh)	DCRR (cents per kWh)
Domestic Service, Domestic Service Time-of-Day, Domestic Service Time-of-Use, Domestic Service Critical Peak Pricing	0.657	-0.024	0.633
Small General, Small General Time of Use, Small General Critical Peak Pricing	0.778	-0.025	0.753
General, General Time of Use, General Critical Peak Pricing	0.635	0.010	0.646
Large General	0.768	0.022	0.790
Small Industrial	0.720	0.033	0.753
Medium Industrial	0.306	0.008	0.314
Large Industrial including Interruptible Rider	0.404	0.027	0.430
Municipal	0.650	-0.023	0.628
Unmetered Services	0.353	0.004	0.357
Gen. Replacement & Load Following	0.110	-0.069	0.040
One Part Real Time Pricing	0.095	-0.004	0.091
Shore Power	0.095	0.059	0.153

SCHEDULE B

DSM Cost Allocation Method~~Approach~~

~~There are 3 kinds of cost benefits resulting from DSM:~~

~~(1) *System* – avoided future infrastructure and related costs, reduced fuel costs, and contribution to achieving environmental and emissions restrictions. All customers receive these benefits.~~

~~(2) *Class* – when customers within a class participate, the whole class benefits by a reduction in their cost of service allocation, even those who do not actively participate.~~

~~(3) *Participation* – customers who are able to participate in DSM programs can lower their own electricity usage and therefore their costs.~~

~~The recovery of DSM costs from customers should reflect the level of benefit received by customer classes. Those customer classes who receive the most benefit (i.e. in all three categories) would bear the most responsibility to contribute to the costs. A customer class that receives only system benefits would contribute to the costs accordingly despite not directly participating in programs. Given the~~

~~nature of DSM programs and benefits it is not possible to precisely calculate and allocate costs based upon these various benefits.~~

~~Allocation of DSM Program Costs~~

~~System benefits are allocated to all applicable customer classes in accordance with the Cost of Service Study (COSS) methodology reflecting allocation of generation rate base as per the most recent rate case decision.~~

~~Once system benefits have been allocated, the remaining costs relate to the class and participation benefits. These costs are assigned to the class(es) participating in the DSM programs in proportion to amounts invested in each class.~~

~~Method~~

- ~~Step 1 – Allocate the system benefits to all applicable customer classes, as 25% of the total Approved DSM program costs, in accordance with the COSS methodology per the most recent rate case decision.~~

- Step ~~2~~1 – Allocate the class and participation benefits by directly assigning ~~75~~100% of the DSM investment identified for each participating customer class.

- ~~Step 3 – Add the amounts from Step 1 and Step 2 to obtain the total amount to be recovered from each class.~~

- Step ~~4~~2 – For NS Power bundled service customers, divide the total amount to be recovered from each class by the anticipated electricity sales for the class to derive the required program cost recovery for each class for the upcoming year.

- Step ~~5~~3 – For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be direct billed in accordance with the customer's class energy bill if served by NS Power under its bundled service offerings.

- Step ~~6~~4 – Annually, true up the class and participation benefits by customer class, as described in BA_1~~based upon actual experience in the 2 years prior to the current PCR year~~.

- Step 5 – At the end of each Approved DSM Term, true up the class and participation benefits by customer class, as described in BA_2.

Conditions

- For bundled service customers other than those who take service in the Wholesale Market (whether in whole or in part), this approach applies to classes as a whole (not to individual customers).

- For customers who take service in the Wholesale Market (whether in whole or in part), this approach applies to individual customers.

- This approach applies to total Approved DSM costs.