DECISION **2026 NSEB 26**
M12661

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for approval of an Extra Large Industrial Dispatchable Above-the-Line Tariff applicable to Port Hawkesbury Paper

BEFORE: Stephen T. McGrath, K.C., Chair
Richard J. Melanson, LL.B., Member

APPLICANT: **NOVA SCOTIA POWER INCORPORATED**
Jennifer Power, Counsel
Mollie Morris, Counsel
Kathleen Murray, Counsel

INTERVENORS: **CONSUMER ADVOCATE**
David J. Roberts, Counsel
Michael Murphy, Counsel

SMALL BUSINESS ADVOCATE
Melissa P. MacAdam, Counsel
Rebekah Powell, Counsel

EFFICIENCYONE
James Gogan, Counsel
Lucia Westin-Eastaugh, Counsel

INDUSTRIAL GROUP
Nancy G. Rubin, Counsel
Brianne Rudderham, Counsel

NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR
David Luther, Counsel
Mark Peachey

PORT HAWKESBURY PAPER LP
David MacDougall, Counsel
James MacDuff, Counsel
Melanie Gillis, Counsel

BOARD COUNSEL: William L. Mahody, K.C.

HEARING DATES: September 21-22, 2026
September 28-29, 2026

FINAL SUBMISSIONS: November 2, 2026

DECISION DATE: **November 24, 2026**

DECISION: **The proposed Extra Large Industrial Dispatchable Tariff is approved, subject to specific changes set out in this decision and several directives.**

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1.0 INTRODUCTION

[1] On December 29, 2025, Nova Scotia Power Incorporated applied to the Board for approval of the Extra Large Industrial Dispatchable (ELID) Tariff. This tariff was specifically designed for Port Hawkesbury Paper LP (PHP). PHP consumes more electrical energy than any other NS Power customer. It is currently served under a below-the-line tariff known as the Extra Large Industrial Active Demand Control (ELIADC) Tariff. Below-the-line rates are specialized tariffs designed to achieve a specific objective. In the case of PHP, the objective was that PHP pay incremental costs and contribute to fixed costs. The ELIADC rate is based on a formula whose inputs change every year. There is an annual true-up mechanism with this tariff.

[2] PHP has an affiliate developing a large-scale wind farm known as the Goose Harbour Lake Wind Farm which will provide power to the NS Power grid. This wind farm is a prescribed generation facility under the *Prescribed Generation Facilities and Energy-Storage Regulations*, NS Reg 160/2024. The arrangement associated with the energy from the Goose Harbour Lake Wind Farm may make the operation of the ELIADC Tariff difficult. Also, the ELIADC Tariff is scheduled to end on December 31, 2026. In any event, PHP prefers more certainty in relation to its power rates. The proposed ELID Tariff is an above-the-line rate. This means it will be set based on a Cost-of-Service Study (COSS) used to allocate all the utility's embedded or accounting costs between all NS Power's above-the-line customer classes. These rates are only changed after a general rate application (GRA).

[3] PHP and NS Power have been working on establishing a rate like the ELID Tariff since 2023. As part of NS Power's 2026-2027 GRA, a Settlement Agreement was reached which addressed certain parameters that should be included in the current ELID

Tariff application before the Board. What the Settlement Agreement means has been disputed by the parties in this proceeding. These parties are NS Power, the applicant and formal Intervenors consisting of PHP, the Consumer Advocate, the Small Business Advocate, and the Industrial Group (which includes 10 large industrial customers). These parties submitted Information Requests (IRs), filed evidence and/or made legal submissions in this matter. Some of the Intervenors retained experts. Board Counsel also retained experts but, as is customary, did not make legal submissions.

[4] The proposed ELID Tariff has the following elements:

- A Customer Charge, designed to recover NS Power's costs to administer the ELID Tariff;
- A Demand Charge, designed to capture the incremental capital cost associated with PHP's peak load demand;
- An Energy Charge, based on the amount of electrical energy PHP consumes;
- Interruptible Service Rider, allowing NS Power, for a credit to PHP, to interrupt the supply of electricity in emergency situations to preserve grid stability;
- Dispatchable Rider, which allows NS Power, in consultation with PHP, to manage PHP's daily load, contributing to the operation of the grid in as efficient and cost-effective a manner as practicable;
- Other Applicable Riders that, like other above-the-line tariffs, currently include a Fuel Adjustment Mechanism (FAM) Rider, a Demand Side Management Cost Recovery Rider and a Storm Cost Recovery Rider;
- Billing Provisions outlining how PHP will be billed or credited under the various parts of the ELID Tariff;

- Tariff Term setting out the minimum notice PHP must provide if it intends to shift to another tariff;
- Treatment of Energy Production from the Goose Harbour Lake Wind Farm, governed by the *Electricity Act*, SNS 2025, c 18, providing how electricity generated from the wind farm will be set off against the amount charged to PHP under the ELID Tariff; and
- PHP Deferral Account, which is designed to allow for the recovery of certain variances between what was included in the assumptions related to the proposed ELID Tariff underlying the approved rates in NS Power's 2026-2027 GRA and the outcome of this application.

[5] This decision focusses on the elements of the ELID Tariff where parties advanced different positions. The Board must decide whether to approve the proposed ELID Tariff. The Board's decision turns on whether the proposed ELID Tariff is just and reasonable as that test is applied in public utility law. The Board has determined that the ELID Tariff should be approved as filed, subject to the following modifications:

- the Interruptible Service Rider credit for 2027 shall be calculated based on $13.107 per kVA of interruptible service instead of the proposed rate of $7.667 per kVA of interruptible service;
- the Dispatchable Rider credit shall be allocated 90% to PHP and 10% to other above-the-line customers instead of all being allocated to PHP as proposed in the application; and
- the operating procedures for the Dispatchable Rider must be approved by the Board rather than being left to PHP and NS Power to determine.

The Board also gives directions about the filing of these operating procedures when they are developed, concerning a review of the COSS methodology related to large interruptible load and the implications on system peak, and on annual reporting about the Dispatchable Rider.

2.0 DISCUSSION AND ANALYSIS

2.1 Settlement Agreement

[6] A Settlement Agreement was filed in NS Power's 2026-2027 GRA. It was signed by all the parties in this proceeding. The Settlement Agreement addressed almost all the GRA issues requiring a Board determination. Of note for this proceeding, the Settlement Agreement had provisions about PHP and an anticipated above-the-line rate applicable to PHP. It has become the subject of much debate in this proceeding. The Board sets out the applicable terms (PHP Treatment Terms) for ease of reference:

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
	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.

[Exhibit N-1, Attachment 4, pp. 11-12 of 21]

[7] The genesis of the Settlement Agreement warrants discussion. The Board was concerned that unlike past settlement agreements, the one in the 2026-2027 GRA

was filed with the application. This meant that while Board Counsel consultants provided evidence about the filing, the formal Intervenors did not. The Board was concerned about the impact this had on the record in the 2026-2027 GRA and whether all the implications of the Settlement Agreement had been fully appreciated by the Intervenors when it was signed. The Board made the following comments:

> [43] However, there is a distinction between what occurred in prior general rate applications and what transpired in the current proceeding. Previously, settlement agreements were concluded after an extensive evidentiary record had been filed with the Board, including many information requests and evidence filed by intervenors (among them the very customers who signed a settlement agreement) and Board Counsel consultants. In the current matter, the settlement agreement was concluded even before the application was filed. While this does not negate the efforts of the parties to reach a settlement, the Board concludes that it is a factor that affects the weight it assigns to the settlement agreement. The agreement is still entitled to some deference but, given the circumstances, it does change the Board's perspective on the settlement. It does not have the full benefit of the parties' views of the application, and the value assigned to various compromises reached in achieving a negotiated settlement. In some instances, the Board was left uncertain about whether certain perspectives had been analyzed or considered. Further, the Board does have the benefit of having the evidence of the Board Counsel consultants, who did not participate in the settlement discussions but were able to conduct an independent review of the application.
>
> [44] A general rate application is a very complex proceeding which raises a multitude of difficult issues. The Board is left with the very difficult duty to ensure that the terms of the settlement agreement are just, reasonable and in the public interest. Following its review, the Board finds that the settlement agreement does contain many terms that are appropriate and should be adopted. However, the Board also concludes that some amendments to the application, as described in the remainder of this decision, are required to ensure just and reasonable rates.
>
> [*Nova Scotia Power Incorporated (Re)*, 2026 NSEB 8]

[8] At paragraph [733] of the *2026-2027 GRA Decision* (*Nova Scotia Power Incorporated (Re)*, 2026 NSEB 8), the Board went on to say that it "…approves most components of the settlement agreement, subject to its findings below that amend the application". With respect to the component of the Settlement Agreement about PHP, the focus was on the treatment of PHP under the COSS allocating utility costs across all customer classes. As there was no new above-the-line tariff applicable to PHP at the time the 2026-2027 GRA application was considered, but one was contemplated, the 2026-

2027 COSS was prepared based on the PHP assumptions that were ultimately included in the Settlement Agreement.

[9] A deferral account was proposed to capture certain variances between the COSS assumptions and the eventual above-the-line tariff. The Board made a comment addressing the uncertainty about what could be included in it:

> [339] NS Power's GRA requested a PHP Deferral to track any revenue differences between the assumptions in the GRA cost-of-service study treating PHP as an ATL customer and the eventual ELID tariff, in the form ultimately approved by the Board. The GRA adopted a clause in the settlement agreement that the PHP Deferral account would apply in the following scenarios:
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> - the Board's decision on the PHP tariff or ADC rider differs from the ATL GRA tariff assumptions;
> - the tariff is not available for PHP to take service under it as of January 1, 2026; or
> - PHP decides the outcome of the ADC and tariff processes is not satisfactory.
>
> [340] In response to Undertaking U-2, NS Power estimated that $18.2 million would accrue in the PHP Deferral account if PHP remains as a BTL customer for the entirety of 2026, and there would also be a $5.7 million fuel balance captured under the FAM. NS Power also assumed the PHP load in 2026 was the same as that assumed in the GRA. The Industrial Group noted that these amounts did not account for delays in PHP's Goose Harbour Wind Project.
>
> [341] While the PHP Deferral contemplated in the settlement agreement was agreed to by the customer representatives, it is clear from the questioning at the hearing that there may be uncertainty about parts of the scope of the deferral account as between NS Power and some of the customer representatives. The settlement agreement contained a clause that the parties were free to take any position they wished during the Board's review of the PHP successor tariff.
>
> [*Nova Scotia Power Incorporated (Re)*, 2026 NSEB 8]

[10] The Board went on to make the following findings:

> [351] While the deferral account was addressed in the settlement agreement, the scope of the account is somewhat uncertain, at least based on the Industrial Group's submissions. However, no party opposed the creation of the PHP Deferral Account. The Board recognizes that there could be significant variances to NS Power's revenue requirement depending on the final adjudication of NS Power's application for the PHP successor tariff. The creation of the proposed deferral account, and the assumptions underlying it, do provide some certainty for the utility and the customer classes. The Board finds that it is appropriate to approve the deferral account.
>
> [352] As to the scope of the deferral account, the Board considers that it is best defined as expressly set out in the settlement agreement. There was no evidence about the scope of the deferral account except for that provided by NS Power, and a reference by Bates

> White. It would be appropriate for customers and other parties to provide evidence on the issue if they consider it necessary. Accordingly, as outlined in part (g) of the "PHP Treatment" section of the agreement, the Board finds that the deferral account will:
>
> > …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.
> >
> > [Exhibit N-27, NSEB IR-1, Attachment 1, p. 12]
>
> [353] Further, any amounts to be transferred to the deferral account will be assessed against the various assumptions agreed to by the parties as inputs to the cost-of-service study applied in the GRA, as set out in sections (a) to (f) in the "PHP Treatment" section of the settlement agreement. As with all deferrals, any transfer to the deferral account is subject to review for prudency.
>
> [*Nova Scotia Power Incorporated (Re)*, 2026 NSEB 8]

[11] With this background, it is perhaps not surprising that parties in this proceeding had significantly different views on what the Settlement Agreement means and how the Board should use it to establish the ELID Tariff. The essence of PHP's submissions can be summarized as follows:

- The terms of the Settlement Agreement are unambiguous. Under the PHP Treatment Terms, clause f) clearly says any party can take any position it so chooses in this application.
- This position is reinforced by the wording on page 2, item 6 of the Terms of Settlement which states the Settlement Agreement is "…without prejudice to any position that may be taken by any Party in any future regulatory proceeding". This ELID Tariff application is a future regulatory proceeding.

- The *2026-2027 GRA Decision* specifically addresses the uncertainty and acknowledges that "…the parties were free to take any position they wished during the Board's review of the PHP successor tariff".
- PHP's position is supported by Board Counsel's Consultants.
- The principles applicable to the interpretation of contracts require that plain language be given its usual and customary meaning.
- The rationale behind creating a deferral account to address the situation where the ELID Tariff would be different than the assumptions in the Settlement Agreement means the parties and the Board all recognized there could be variances between what is expressed in the PHP Treatment Terms and a Board-approved ELID Tariff. Preventing PHP from taking different positions than what is set out in the Settlement Agreement defies commercial reality. PHP would never have signed the Settlement Agreement without the express language indicating it was not bound by the PHP Treatment Terms in a subsequent ELID Tariff application.
- The Board should decide this application based on the evidence before it and the applicable public utility regulatory principles.

[12] The Industrial Group takes a different approach to the Settlement Agreement which the Board has summarized:

- NS Power and PHP were obligated to advance the determinants set out in the Settlement Agreement.
- The settlement agreement does not predetermine the outcome of this proceeding.

- PHP is challenging assumptions it proposed, negotiated, and ultimately accepted which it now disavows because there may be more advantageous assumptions. The Board should approach this position with caution.
- The reservation in clause f) contemplates the parties would have the opportunity to test the 2026-2027 GRA settlement assumptions against a full evidentiary record.
- The issue before the Board is not whether the settlement figures must be accepted because they appear in the Settlement Agreement, nor whether PHP can selectively abandon determinants that it previously proposed and accepted. The issue is whether, on the evidentiary record now before the Board, those determinants produce rates that are just and reasonable.

[13] The Consumer Advocate supports using the PHP Treatment Terms as the basis for the ELID Tariff pursuant to these key submissions:

- The Board does not have to accept the terms of the ELID Tariff simply because it complies with the Settlement Agreement, based on general principles about the Board's discretion to approve settlement agreements. However, the Settlement Agreement should be given significant weight based on these same principles. Clause f) does not give PHP *carte blanche* when it comes to taking positions on this application.
- Interpreting Clause e) in its proper context leads to the conclusion it was only meant to apply to the items listed in clause e) about the Active Demand Control (or Dispatchable Rider as framed in this application).

- An interpretation that allows any party to take a position different from the terms of the Settlement Agreement would lead to an absurd result in that NS Power would be free to oppose its own application.

[14] NS Power's position on the Settlement Agreement is like that of the Consumer Advocate:

- PHP and NS Power committed to bringing an application with the 2026-2027 GRA assumptions and PHP should be bound to this commitment.
- This position is supported by the short period contemplated between signing of the Settlement Agreement and the anticipated ELID Tariff application.
- While NS Power and PHP are obligated to base the ELID Tariff application on the PHP Treatment Terms in the Settlement Agreement, other parties can take alternative positions in accordance with clause e).
- However, like the Consumer Advocate, NS Power says the exemption under clause e) only applies to the Active Demand Control component of the ELID Tariff.

[15] The Small Business Advocate's submission was brief. While acknowledging there are differing views about the Settlement Agreement, the Small Business Advocate said "…the main issue before the Board in this matter is whether the proposed ELID tariff in the ELID Application is reasonable and should be approved and the impact of the GRA Settlement Agreement, while an important consideration, is not the key issue or determining factor".

2.1.1 Findings

[16] The Board finds that the Small Business Advocate has succinctly described how the Board should approach the Settlement Agreement. As a starting point, despite PHP's strenuous argument to the contrary, the Settlement Agreement contains

ambiguities and is inconsistent with how this application was brought to the Board. Clause e) of the PHP Treatment Terms anticipated that PHP and NS Power would file a written tariff that incorporated the load characteristics set out in clause b) and the dollar value of the interruptible credit and the value of the priority interruptible credit set out in clause c). Clause d) made it clear the value of the Active Demand Control or Dispatchable Rider had not yet been decided. PHP and NS Power committed to completing "discussions and analysis" of a cost-based value to this component, which is akin to an agreement to agree. Clause d) also contemplated that PHP and NS Power would bring the current application in 2025. PHP committed to take service under the new 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". No application with a joint written tariff was brought in 2025, or at all. As between PHP and NS Power, it appears there is agreement about the value of the Dispatchable Rider contemplated by clause d). The meaning of the words "and tariff processes" in clause d) is less clear. There was evidence and argument in this proceeding about operating procedures that needed to be developed governing dispatch under the Dispatchable Rider. The disagreement between the parties was focussed on whether the operating procedures should be subject to Board approval. These operating procedures had not yet been finalized at the time of the hearing. The words "tariff processes" are used in conjunction with the Dispatchable Rider, where a resolution was required before an application, as contemplated by the Settlement Agreement. One potential interpretation is that "tariff processes" in clause e) refers to the operating procedures needed to implement the Dispatchable Rider.

[17] This brings us to clause f) of the PHP Treatment Terms and whether the meaning of this clause is clear and unambiguous as suggested by PHP. The clause must be read within the context of the clauses that precede and follow it. The operative part of the clause says "…it remains open for all Parties to take any position they so choose…". Since PHP was a party to the Settlement Agreement, the company says that it is not bound by any of the tariff parameters and characteristics outlined in the rest of the Settlement Agreement. From PHP's perspective, this is because the wording preceding the operative part of the term refers to both the Active Demand Control and tariff process, and the wording that follows the operative phrase, which addresses challenges to the tariff based on inconsistencies "…with the load characteristics and basic structure set out above", uses the conjunctive "including". PHP says this means challenges to the tariff are not limited to inconsistencies with the load characteristics and basic structure set out in the preceding clauses of the Settlement Agreement. PHP says this interpretation is reinforced by clause g) creating the deferral account, as well as a general clause in the Settlement Agreement stating that the entire agreement was without prejudice in a future regulatory proceeding.

[18] NS Power and the Consumer Advocate say that PHP's interpretation is absurd because that means, as PHP suggested in evidence, that NS Power could oppose its own application. It would also mean that if PHP had joined in a written tariff incorporating the billing structure set out in the Settlement Agreement, it could also have opposed its own application. Where PHP did not submit such a written tariff, the Consumer Advocate argues PHP's interpretation would allow it to challenge the very billing parameters it agreed to in the Settlement Agreement. The Consumer Advocate

submits that the only billing parameter that parties should be able to challenge under the terms of the Settlement Agreement relate to the Active Demand Control or Dispatchable Rider component and any associated tariff processes which were left to be resolved after the signing of the Settlement Agreement. The Industrial Group submits that PHP and NS Power were obligated to advance the billing determinants and tariff structure agreed upon in the Settlement Agreement. However, the Industrial Group appears to leave open the possibility that any party can challenge any component of the ELID Tariff application, with the benefit of a full record. The Industrial Group appears to be saying that if PHP does so its alternative positions should be given less weight. Not surprisingly, the parties marshalled their evidence based on their interpretation of the Settlement Agreement.

[19] Despite PHP's strenuous arguments to the contrary, the Settlement Agreement is ambiguous. There is a conceptual difficulty with the Settlement Agreement. The PHP Treatment Terms propose a written tariff from two of its signatories, with defined parameters about certain billing determinants related to peak load at three coincident peaks; firm plus interruptible load; forecast usage; the dollar value of the interruptible credit; and a valuation of a priority interruptible credit. However, it also contains a clause that PHP has interpreted as meaning any party, including the parties who agreed to file a written tariff in accordance with the agreed upon parameters, can challenge those very parameters when the tariff application is filed. The conceptual difficulty can be overcome by reading clause f) so that it only applies to the Active Demand Control component of the Settlement Agreement that was subject to further negotiation. The "tariff processes" referenced in clauses e) and f) could be interpreted as being restricted to the operating procedures surrounding dispatchability. This is an objective, plausible, commercially

reasonable interpretation consistent with the words used. This would mean that “taking any position” would be limited to the “ADC and tariff processes” component of the PHP Treatment Terms under the opening language of this clause, which had not yet been agreed upon when the Settlement Agreement was signed. Turning to the closing language, if the “ADC and tariff filing(s) is inconsistent with the load characteristics and basic structure” the parties agreed upon, any party could challenge them. The Board notes the language here is “tariff filing(s)” which is broader than the wording “tariff processes”. The word “including”, while not suggesting an exhaustive list, can be interpreted to mean parties could challenge other deficiencies in the proposed tariff which are similar in nature to departures from the agreed upon load characteristics and basic structure in the PHP Treatment Terms.

[20] The foregoing interpretation would be consistent with the deferral account discussed in clause g) of the PHP Treatment Terms. Part a) of clause g) addresses any Board-ordered deviations from the PHP tariff assumptions regardless of any party’s position or the terms of the Settlement Agreement. This clause simply recognizes that with a full record and an actual tariff to consider, the Board has the jurisdiction to make its own determination about any element of the ELID Tariff. Part b) of clause g) addresses the situation that in fact occurred; namely, that there was no available ELID Tariff in 2026. If “tariff processes” is restricted to the dispatchability operating procedures, then part c) of clause g) would provide PHP an out if the last part of the Settlement Agreement left to be negotiated does not produce a satisfactory outcome.

[21] On the other hand, PHP’s interpretation does not create an absurdity, as suggested by some Intervenors, if the negotiations surrounding the Settlement

Agreement, from PHP's perspective, are placed in context. Bevin Lock, Co-Mill Manager, confirmed that PHP did not agree with all aspects of the billing determinants that were being proposed in the Settlement Agreement. He testified about this:

> **A.** (Lock) That ahead of signing the Settlement Agreement, we were aware that there were aspects that were being modelled that we did not agree with the approach, and that to be able to move things forward, as in all settlements between parties, we accepted those, along with the caveat that PHP would have the ability, like any other party, to take any position we so choose, including whether or not the ADC Tariff filings are consistent or inconsistent with the structure. So as outlined in (f) of the Settlement Agreement.
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> [Transcript, September 28, 2026, pp. 79-80]

[22] The Settlement Agreement was being negotiated before the filing of the 2026-2027 GRA. There were time pressures related to the filing and finding a replacement for PHP's existing below-the-line tariff. Mr. Lock, and PHP's consultants, Brubaker & Associates, Inc. (Brubaker), were clearly concerned about some aspects of the modelling being used for the COSS and the proposed ELID Tariff. However, the COSS had to be developed to allocate a revenue to all rate classes that would end up being the subject of the 2026-2027 GRA filing and the accompanying Settlement Agreement. It appears to the Board that PHP was trying not to be obstructionist in the settlement process. However, the company wanted to preserve its right to advance different billing determinants or modelling when the ELID Tariff application was eventually filed. This is what PHP believed clause f) of the PHP Treatment Terms accomplished. The Board accepts PHP's evidence that it would not have signed the Settlement Agreement without a reservation of rights to advance alternative scenarios in this ELID Tariff application. PHP did not communicate its reservations about the modelling parameters in the PHP Treatment Terms to other parties before the Settlement Agreement was signed. It appears PHP believed the language of the exemption would

be obvious to all parties. Unfortunately, that was not the case, and the Board has before it four possible interpretations, although the NS Power and the Consumer Advocate positions are similar.

[23] NS Power position appears to be that, with the benefit of a full record, parties other than PHP and NS Power can challenge any part of the proposed ELID Tariff. The Industrial Group appears to support this position, to some extent, because of the way it approaches how PHP alternative positions should be addressed. Rather than interpreting the language used in such a way as to resolve ambiguities, NS Power appears to propose changing the meaning of “any party” in clause f) to “any party except PHP and NS Power”. At least a part of the reasoning behind this submission is that NS Power and PHP committed to the billing parameters expressed in clauses b) and c). The difficulty is that while the other Intervenors may not have had the same access to information as NS Power and PHP, they also committed to these same parameters by signing the Settlement Agreement. From the Board’s perspective, the PHP Treatment Terms mean that either all parties can take whatever position they want on all aspects of these terms, or all parties can take whatever position they want on the unresolved Active Demand Control or Dispatchable Rider component.

[24] As the parties had different approaches to the meaning of the PHP Treatment Terms, the Board has relied primarily on the actual words used, rather than what the witnesses said the PHP Treatment Terms meant after the fact. PHP’s position is understandable from its perspective. It does not warrant the type of potential sanctions the Consumer Advocate proposes the Board should consider. However, on balance, the Board finds that the most plausible interpretation of the interplay of the various clauses in

the Settlement Agreement is as set out in paragraphs [19] and [20] of this decision. This means PHP's position, and to some extent, that of NS Power and the Industrial Group, are not accepted. That said, a settlement agreement in a public utility rate setting context is a special kind of agreement. It does not involve a purely contractual arrangement between private parties. It impacts all ratepayers and invokes public interest considerations. Ratepayer groups cannot contract out of the Board's public interest oversight role, and the output of a settlement agreement must result in just and reasonable rates to be approved by the Board. In the *2026-2027 GRA Decision*, the Board described the potential problems with the way this Settlement Agreement was negotiated before a full record was available. It gave qualified support to the Settlement Agreement. In fact, the Board's comments at paragraph [341], while made in the context of the scope of the proposed deferral account, may have contributed to PHP's view that any party could challenge all aspects of the PHP Treatment Terms.

[25] There was not a full discussion about the meaning of the PHP Treatment Terms of the Settlement Agreement in the *2026-2027 GRA Decision*. The Board expressed concerns about the intervenors understanding of certain issues when it was signed. The Board does not believe its findings on the interpretation of the PHP Treatment Terms in the Settlement Agreement fundamentally changes what it should do in this proceeding. Because there may not have been a complete meeting of the minds about the Settlement Agreement, in the public interest, the Board will not limit what evidence or arguments it will assess. As well, the Settlement Agreement had a general term that said it was without prejudice to future regulatory proceedings. This is undoubtedly such a proceeding.

[26] The Board has a much more complete record about the proposed ELID Tariff than in the 2026-2027 GRA. That evidence has been fully tested and is supported by detailed submissions. Therefore, despite its findings on the meaning of the PHP Treatment Terms of the Settlement Agreement, the Board comes back to the Small Business Advocate's submission that "…the main issue before the Board in this matter is whether the proposed ELID Tariff in the ELID Application is reasonable and should be approved and the impact of the GRA Settlement Agreement, while an important consideration, is not the key issue or determining factor". In fact, while using varying language, all parties recognized this general principle. The Settlement Agreement was the basis for the approved COSS and the eventual rates established in the 2026-2027 GRA. All parties were aware of how important this was. The existence of a deferral account should not be used to minimize its importance. However, in the final analysis, the use the Board makes of the Settlement Agreement becomes an issue of weight, as it was in the 2026-2027 GRA. While important, because of the various concerns the Board has, it should be afforded less weight than might otherwise be the case. For example, it could be helpful if the evidence and applicable legal principles do not clearly favour one outcome over another.

[27] The Board will comment on one last issue about the Settlement Agreement. PHP was very concerned that the Board allowed questions about the Settlement Agreement negotiations and the chilling effect this could have on future settlement negotiations. The questions were limited in scope and meant to elicit evidence about how an ambiguous Settlement Agreement should be interpreted. NS Power and some Intervenors suggested that parties should be held to their bargains and the chilling effect

on future settlement agreements if they are not. It is the Board's opinion that while settlement agreements can be very useful and should be encouraged, ambiguous settlement agreements made in the absence of a full record should be discouraged. The Board is certainly aware of the need to keep settlement negotiations confidential. There is a corresponding need to avoid ambiguity. The Board will safeguard the confidentiality of negotiations within those parameters. Ambiguous settlement agreements that could impact all ratepayers should be avoided and discouraged.

2.2 Customer Charge

[28] NS Power's proposed ELID Tariff includes a monthly Customer Charge of $10,000 to recover costs associated with provision of dispatch service to PHP and to administer the tariff. The following eight tasks were identified as components of the Customer Charge:

- 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 Dispatchable Rider benefit (Dispatchable Rider credit);
- Periodic PLEXOS and PortOps modeling and report preparation;
- Real-time optimization of PHP load to achieve the most economic system dispatch; and
- Providing dispatch instructions to PHP based on economic dispatch optimization results and real-time system conditions.

[29] In its evidence, Board Counsel consultant, Bates White Economic Consulting, raised concerns about the amount of the monthly fee. Referencing a table provided in the application, Bates White noted that it contained a low and high estimate for each task, which was summed to provide an approximate cost per month. The low estimate is $10,000/month and the high estimate is $14,583.33/month.

[30] Bates White stated that NS Power's methodology for developing the estimate is not well explained in its application, nor is it compelling. Furthermore, it stated that the decision to select the low value is unsupported and is likely to under-collect the costs intended to be recovered by the Customer Charge.

[31] Bates White recommended that additional evidentiary support for the proposed Customer Charge should be filed by NS Power. Alternatively, the Customer Charge could be set at $12,291.67/month, which is the midpoint of the estimated range, and if a reconciliation determines that actual costs of ELID Tariff administration are below the Customer Charge collections, PHP would receive 100% of that amount in credits. Bates White also recommended that NS Power should explain the methodology for tracking the costs of administering the ELID Tariff and how it plans to ensure that 100% of the costs incurred in administering the tariff are paid by PHP, including costs that exceed the Customer Charge collections.

[32] NS Power said that it sought to be transparent about the uncertainty regarding the Customer Charge costs forecasts for the initial tariff offering and why a high-level estimate of $10,000 per month was appropriate until experience with the tariff is acquired. It also noted that Bates White's suggested midpoint estimate was no more defensible than NS Power's proposed amount. NS Power also noted that several of its

tariffs include customer charges, but none include individual tracking against revenues. It stated that no revision is required and that the amount of time and effort needed to track and report on those costs would add costs far out of proportion to the associated costs. It further stated that additional and improved Customer Charge costs information will be available in the next GRA.

[33] Another issue raised regarding the Customer Charge is "optionality". In its Closing Submissions, PHP stated that the primary justification for the Customer Charge is the cost associated with administering the Dispatchable Rider operating procedures and credit calculation, so no charge should be applicable if it decided not to take service under the Dispatchable Rider. The Small Business Advocate and the Industrial Group both took exception to PHP's suggestion.

[34] In its Reply Submissions, the Small Business Advocate stated:

> The ELID Application states the "Customer Charge is designed to recover the costs associated with the provision of dispatch service to **PHP and to administer the Tariff**" (Emphasis added). The SBA respectfully submits that does not equate to PHP's characterization that the customer charge is "fully justified on the basis of the costs associated with administering the DR" and therefore should be subject to removal if there is no DR….Moreover, the SBA respectfully submits that the ELID Application does not give a breakdown of the dispatch or tariff administration costs included in the Customer Charge so there is no way of knowing what the Customer Charge covers, other than acknowledgement that some portion of it is contributes to the cost of facilitating the DR.
>
> …
>
> The SBA respectfully submits that PHP raises new issues in their closing submission that were not presented as evidence or tested through cross-examination at the hearing. Consequently, no one has had a chance to consider or challenge them and therefore they are not properly before the Board. [Emphasis in original] [Footnotes omitted]
>
> [Small Business Advocate, Reply Submissions, pp. 3-4]

2.2.1 Findings

[35] The Board has considered NS Power's position regarding a high-level Customer Charge estimate of $10,000 per month being the appropriate amount until experience with the tariff is acquired. NS Power said that additional and improved

Customer Charge costs information will be available in the next GRA. However, it is unclear how “additional and improved” cost information will be available if those costs are not being tracked. This is particularly notable considering NS Power’s reference to the uncertainty regarding the Customer Charge costs forecasts. Given that uncertainty, the Board accepts NS Power’s estimated $10,000 monthly Customer Charge but directs it to abide by Bates White’s recommendation to track costs so that an appropriate Customer Charge can be determined in NS Power’s next GRA.

[36] Regarding the PHP suggestion that no Customer Charge should be applicable if it decided not to take service under the Dispatchable Rider, the Board does not agree. The Board accepts that costs other than for only Dispatchable Rider administration may be included in the Customer Charge. In any event, as considered later in this decision, the Board finds that the Dispatchable Rider is a mandatory component of the ELID Tariff, and is not optional.

2.3 Demand Charge

[37] Under NS Power’s cost-of-service methodology, costs that are associated with providing required capacity to serve customers are classified as demand costs. NS Power currently uses a three coincidental peak (3CP) approach to allocate demand costs to its above-the-line customer classes. This approach considers how much capacity is used by each customer class when the electricity system is at its peak level of demand in the months of December, January and February.

[38] For some rate classes, such as the Large Industrial class, demand-related costs (or a portion of them) are recovered through a demand charge. The proposed ELID Tariff includes a demand charge that differs from the demand charge under the Large Industrial Tariff in two ways:

(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 [above-the-line] 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).

[Exhibit N-1, pp. 5-6]

[39] On cross-examination by PHP's counsel, NS Power's witnesses discussed the use of judgment in setting PHP's level of demand:

Q. So can you help me with understanding on how you're proposing to reset the demand determinant applicable to PHP going forward? What's the -- what's the methodology that we're having approved in this Application that will carry on since we're trying to get an above-the-line tariff put in place for Port Hawkesbury Paper?

A. (Ferguson) The methodology -- because of the unique characteristics of Port Hawkesbury Paper, where it is dispatchable load with a -- it is the largest customer on the system with a very high peak load relative to other customers, a significant average load relative to other customers, and a potentially low value at time of 3CP, I think we're going to have to consider further what the right number is that provides appropriate allocation, recognizes Port Hawkesbury Paper's contribution to 3CP, but also provides for fair allocation of costs across classes.

The judgment we're talking about is that exercise; what's the appropriate level? There's been a couple of different views put forward in this Application: Port Hawkesbury Paper should rely on the firm figure only; Mr. Bowman used an average number, and the Settlement Agreement provides for a number that's roughly in the middle of those two options.

So an objective of utility pricing is to provide for fair allocation of costs. We'll need to consider going forward as part of GRA process what the fair figure is for Port Hawkesbury Paper. We've – I think we have the benefit through the Settlement Agreement of having a solid foundation for the first two years of the tariff, 2027 now, and I think it -- the figure that we're using has historical foundation, recognizes that Port Hawkesbury Paper is likely to be lower relative to its average load during time of 3CP, but also relies significantly on the transmission and generation systems in that. In total, they account for 8 percent of the power system load after the provision for the Goose Harbour Lake Wind Farm 4 or 5 percent. So we think the judgment is in trying to find that right number and it may not be able to rely on historical or purely forecast figures at time of system peak, like we do for other classes.

[Transcript, September 21, 2026, pp. 77-79]

[40] In the present application, NS Power proposes a demand determinant for PHP of 65 MW, comprised of 8 MW of firm and 57 MW of interruptible demand. This demand characteristic was referenced in the Settlement Agreement and used in the COSS to set rates in NS Power's 2026-2027 GRA. NS Power also said that this demand assumption was used in prior forecasts for estimating PHP's 3CP demand.

[41] In response to SBA IR-1(a), NS Power further described its rationale for using a 65 MW demand determinant:

> The 65 MW is a figure that has been used in prior forecasts for estimating the demand of PHP at the time of coincident peak. This value, 65 MW, is based on the optimized load profile for PHP developed for the 2012 Stern Paper Mill Load Study, and has been periodically confirmed to remain a reasonable quantity. Please refer to Table 2 on page 15 of the Evidence of Colin T. Fitzhenry and Michael P. Gorman, Brubaker & Associates Inc. (BAI). As observed by BAI, "the average of the 2022 and 2023 PHP demands at the winter CPs is 65,332 kW, or approximately 65 MW." The 65 MW figure was used in the 2026-2027 General Rate Application (GRA) Cost of Service and, as part of the GRA Settlement Agreement (SA), was determined by parties to be reasonable as the foundation for 2026 and 2027 PHP ATL Tariff costing. [Footnotes omitted]
>
> [Exhibit N-9, SBA IR-1(a), p. 2]

[42] In Undertaking U-2, NS Power was asked to provide the 2012 Stern Paper Mill Load Study and it provided two confidential attachments that were filed by Pacific West Commercial Corporation (PHP's predecessor) in a proceeding before the Nova Scotia Utility and Review Board considering a request by that company for a load retention tariff (Matter M04862).

[43] In Undertaking U-3, NS Power was asked to provide the assessments it had completed to periodically confirm that a demand assumption of 65 MW remained reasonable. Its response provided three-, four- and five-year moving averages of PHP's demand during the winter peaks from 2016 to 2025 (adjusted for losses using 4.2%). The average of the averages over this period was 64 MW (three-year) and 65 MW (four- and

five-year). However, there is some basis for concluding the moving averages used for 2024 and 2025 may be somewhat overstated.

[44] In response to IG IR-30(a), NS Power was asked to update PHP's historical coincidental peaks for 2024 and 2025. The average coincidental peak demand over this period was 28 MW; however, PHP's response to Undertaking U-20 suggests that the value NS Power showed for PHP's coincidental peak on January 19, 2024, was too high.

[45] In its Closing Submissions, NS Power said that the demand figure used in the ELID Tariff would need to be reviewed and re-examined over time. It said determining a demand figure for PHP is complex and requires the consideration and weighting of several factors to ensure that the demand assumptions are equitable across all customer classes and reflect PHP's actual use of the system as much as possible.

[46] In its written evidence in this matter, PHP expressed concern about the use of a 57 MW winter month system coincident peak demand for its interruptible load. It said given NS Power's dispatch control and ability to interrupt its load, the utility had tools to manage PHP's load around peak events on the system, and it was "not appropriate to determine a demand charge based on PHP's historical load levels during coincident peak hours".

[47] PHP's consultant, Brubaker filed evidence stating that including interruptible demand in the development of a 3CP allocator over-allocates capacity costs to PHP because NS Power serves PHP's interruptible demand on an "as-available basis" and does not incur resource capacity costs in doing so. It said a similar cost-causative relationship existed for NS Power's transmission system, noting it was Brubaker's understanding that transmission planning assumes that PHP's demand on the

transmission system is minimal during system peaks. Therefore, Brubaker said PHP's load was not a driver for additional transmission investment or capacity expansion. Brubaker recommended that PHP's 3CP firm demand of 8 MW be used in the capacity cost allocator.

[48] In CA IR-9, NS Power said assigning demand-related costs to PHP based on 8 MW of 3CP demand would be "clearly unfair and result [in] cost transfers to other classes and [was] inconsistent with long-established practice in Nova Scotia". NS Power noted that PHP's average and peak loads were considerably more than its 8 MW firm demand and asserted that PHP's proposed treatment would avoid transmission cost responsibility, "when transmission systems are designed to meet an area's total load, not its firm load only". It also said this is inconsistent with how interruptible service has been compensated for decades in Nova Scotia, which is based only on the avoided cost of generation, not transmission. Board Counsel consultant, Synapse Energy Economics, Inc., and the Consumer Advocate's consultant, InterGroup Consultants, expressed similar opinions in their evidence.

[49] InterGroup described this as a "common problem with 'interruptible' loads that reflect a considerable portion of a customer's ordinary electricity needs". InterGroup noted that there are alternative cost allocation methods that could address this in other jurisdictions, but in the context of the Settlement Agreement, it considered that the load parameters modelled by NS Power were reasonable and should be approved.

[50] The Industrial Group's consultant, Patrick Bowman, of Bowman Economic Consulting Inc., also thought the proposal to use 8 MW was inappropriate. He considered NS Power's response to CA IR-9 to clearly rebut this proposal, noting that PHP is not a

viable operation at 8 MW. He said using this as the demand assumption would mean PHP would avoid paying for basically any transmission or generation capacity despite receiving material annual service.

[51] Mr. Bowman's recommended that the capacity value used in the cost of service for PHP should be representative of the expected PHP average demand based on total forecast energy requirements (before non-dispatchable wind energy credits) at a high load factor. As discussed in more detail later in this decision, the Dispatchable Rider under the proposed ELID Tariff is intended to credit PHP with electricity system savings produced by shifting its load from an assumed high load factor customer baseline to a load profile that is optimized for the overall electricity system. Mr. Bowman said the assumed customer baseline load profile should also be used to establish costing for PHP's load. Mr. Bowman also said that information requests in this proceeding, including information filed confidentially in CA IR-9 and Synapse IR-24, Attachment 1, supported a PHP demand allocation based on 120 MW. However, he left it open to NS Power to provide updated values consistent with the concept of a high load factor customer baseline load. The Industrial Group submitted that PHP's required demand was higher than the 3CP demands proposed by NS Power and PHP under a sustainable level of operations:

> The IG submits that a sustainable operating load is the appropriate proxy for the demand that PHP would impose at system peaks absent prior dispatch. Mr. Bowman's 120 MW recommendation is the only one of the three options that is analytically coherent with the premise of an [above-the-line] rate and reflects the demand on which NSPI has, in fact, built its system. NSPI's evidence indicates that PHP's average operating load is approximately 15 times its proposed 8 MW firm load—that is, approximately 120 MW. Additionally, on cross-examination Mr. Ferguson, on behalf of NSPI, confirmed that outside of the historical 3CP, PHP would be "operating in a more normal levels [sic]", and confirmed that would be "in excess of 100 megawatts", and confirmed their average load was 120 MW.
>
> The best evidence of PHP's sustainable load is found in the now non-confidential breakdown of PHP's operating modes at Exhibit 16(i), Attachment 2. As is evident from

> that document, PHP must consume between 106-120 MW in order to be at a sustainable business production level.
>
> More specifically, the current Operating Mode ("**OM**") 6 requires a demand level of 106-120 MW, in order to operate the paper machine, bleaching, and thermomechanical pulp line 3. That mode is recorded as a priority "1", meaning, it is of the highest priority. As described by Mr. Lock, "[s]o in an operating period and not in a down day, those are – those are the operating modes" and "…when we are running, making paper and that stable operating, the priority would be those OMs in the range of the 90 to 105 or 90 to 115, in and around there. One twenty (120) as it stated here; sorry." [Footnotes omitted]
>
> [Industrial Group, Closing Submissions, pp. 6-7]

[52] In its Closing Submissions, the Industrial Group argued that PHP was already compensated for historical load shaping under the ELIADC and that unless a demand assumption is used that is undistorted from the historical influence of active dispatching, PHP would be compensated for the same benefit twice. This concern was succinctly set out in the Industrial Group's Reply Submissions:

> The IG's concern is that the tariff uses two different assumptions about PHP's load. It allocates embedded costs using a profile already reduced by dispatch, but calculates PHP's DR credit against a materially higher, flat profile. Those assumptions must be reconciled. Otherwise, the tariff risks recognizing the effect of dispatch in PHP's lower allocated costs while also paying PHP separately for that dispatch.
>
> [Industrial Group, Reply Submissions, p. 2]

[53] Brubaker considered Mr. Bowman's approach to be suggesting that average demand should be used to determine PHP's contribution to the system winter peaks. Brubaker said this did not align with NS Power's need to invest in system capacity and was discriminatory because it treated PHP differently than other customers. In its view, Mr. Bowman's approach over-allocated system resource production and transmission capacity costs to PHP. NS Power said, in its rebuttal evidence, that 120 MW "likely overstates PHP's load at time of system peak, but this remains to be determined".

[54] In its Closing Submissions, PHP disagreed that it would be operating at a high load factor during of the winter system peaks. It argued:

> Adopting the type of approach suggested by Mr. Bowman implies that PHP would be running at load levels greater than its second highest operating mode at all coincident peaks, which is simply not reasonable. Further, it attempts to exclude the impact of PHP's dispatchability on the 3CP determination on the basis that PHP is already receiving a DR credit, ignoring the fact that the DR credit calculation is based on hourly energy cost savings across the entire year, not the avoidance of long-term fixed capacity costs that are being allocated using the 3CP allocator as part of NS Power's COSS.
>
> [Port Hawkesbury Paper, Closing Submissions, p. 18]

[55] PHP went on to submit that the 3CP allocator is designed to allocate costs based on what actually drives NS Power's system peaks. It said it was inappropriate to allocate demand costs to PHP that are not reflective of the expected demand it will place on the system at the time of the winter system peaks.

[56] In its Reply Submissions, PHP also addressed the double-counting issue raised by the Industrial Group. It argued there is no double counting because the costs are distinct. It said that the "fixed demand costs that are allocated to NS Power's customers using the demand at 3CP are fundamentally different from the variable energy costs that are allocated to customers and subject to a credit for dispatchability".

[57] In its Closing Submissions, PHP said that the ELID Tariff demand charge should be set based on cost causation, and emphasized that NS Power's approved approach for allocating demand costs is the 3CP methodology:

> NS Power's approved method for allocating demand costs to [above-the-line] customers as part of its COSS is similarly focused on cost causation at the time of system peaks. In its COSS process document that was filed as Appendix 12A in NS Power's 2026/27 GRA, NS Power stated as follows at page 24:
>
> > "Allocators are used to determine cost responsibility. As noted above, costs classified to demand are associated with the cost of providing required capacity to serve customers. For this reason, **looking at the drivers of system peaks is the primary factor to consider when determining cost causation**, which is one of the considerations that goes into the approach to allocating demand costs in a manner that reflects cost responsibility.
> >
> > The second factor that is looked at when determining the allocation of demand costs is volatility, which is **generally controlled by looking at a number of system peaks rather than a single peak event. NS Power currently utilizes a fixed 3 CP approach**. NS Power is a winter peaking

> utility so it looks to the top system peak in each of the months of December, January and February, which are generally the coldest months in the province to determine its allocation of demand costs. NS Power investigated, several other potential approaches to this, but **determined that the current approach continues to reflect cost causation while also balancing volatility and allocation of costs year over year by assessing cost causation across the three coldest months**. This analysis conducted by NS Power is demonstrated by the data included in its response to DR-88."
>
> When this NS Power statement was put to him by PHP counsel, Mr. Bowman noted that: "I'm not sure I can fully support that the 3 CP is the best, but it is the current method and it's been approved for use in this jurisdiction. So I accept all of that." [Emphasis in original] [Footnotes omitted]
>
> [Port Hawkesbury Paper, Closing Submissions, p. 15]

[58] However, PHP said it recognized that while it has operated significantly below its average running load at times of system peak, and its actual metered load at 3CP in 2024 and 2025 has been minimal, this has not always been the case. It also said it recognized that, to date in Nova Scotia, the interruptible credit is only provided in relation to generation assets. It agreed there was some historical basis for NS Power's proposed 65 MW demand assumption, noting this approximated PHP's average running load while operating a paper machine and its bleaching plant, but not running pulping operations. It also said that NS Power's response to Undertaking U-3 suggested a demand assumption in this range even before Active Demand Control was introduced under the ELIADC in 2020.

[59] Based on this, PHP said that if its position on the appropriate value for the interruptible credit were adopted (addressed later in this decision) it accepted it would be reasonable for the Board to adopt 65 MW as PHP's assumed demand for the purposes of this proceeding. Going forward, it suggested a methodology grounded in an average of prior actual metered load at the system peaks over a representative period, such as five years, adjusted for any forecasted changes, was the most appropriate solution. It

asserted such an approach would ensure consistency, clarity and stability in the rate design and would be "free from any one party's subjective 'judgment' as expressed by NS Power".

[60] In its Closing Submissions, NS Power argued that using a strict 3CP approach for PHP was not appropriate and it asserted that some degree of subjectivity was "inevitable". It said:

> The fact that a strict 3CP approach is appropriate for other ATL customers does not mean that 3CP is appropriate for PHP ATL. PHP's rate structure and load is more complex than other ATL customers. Ignoring these complexities when determining PHP's demand figure will result in an unfair representation of PHP's use of the system, to the detriment of other classes. As a result, it is required to look beyond what the actual 3CP number is to make sure that it produces a fair outcome.
>
> [NS Power, Closing Submissions, p. 9]

[61] In its Reply Submissions, PHP expressed concern about NS Power's apparent intention to leave the allocation of demand-related costs to PHP open to subjective judgments about what is fair. It said:

> …With respect, fairness is achieved by the consistent application of the Board-approved COSS methodologies across customer classes grounded in actual data, not by one party's judgment. As the Board stated in its decision approving a new 2-Part Real-Time Pricing Rate for a predecessor mill to PHP, StoraEnso, back in 2006:
>
> > [110] In the Board's view, if cost of service is to be used as a tool to design rates, then **fairness requires that the same cost of service methodology apply to all rates.**
> >
> > …
> >
> > [113] **Fairness requires that all rates, that are designed based on cost of service, use the same cost of service methodology.** Accordingly, for purposes of the rates calculated in this proceeding including the 2P-RTP rate, they will be based on the Board approved cost of service methodology.…
>
> Notably, this is how the 65 MW assumption is referenced in section b) of the PHP Treatment in the SA Terms of Settlement – "based on prior actual PHP metered load at the time of NSP's 3CP." [Emphasis in original] [Footnotes omitted]
>
> [Port Hawkesbury Paper, Reply Submissions, p. 13]

2.3.1 Findings

[62] The selection of the determinant for allocating demand-related costs to the ELID Tariff class (which consists only of PHP) poses a challenge for two reasons. The first is that, for years, PHP's load has been subject to dispatch directions from NS Power. The shape of its load without this influence is subject to some uncertainty. The second is that the size of PHP's load, coupled with its ability to shape it down to very low levels, tests the limits of NS Power's existing 3CP cost allocation methodology.

[63] Allocating demand-related costs under NS Power's approved 3CP methodology uses each class's forecast demand at the time of the three winter peaks in December, January and February. Fundamentally, the Board agrees with the statements made by the Nova Scotia Utility and Review Board in *Re Nova Scotia Power Inc.*, 2006 NSUARB 97, cited by PHP in its Closing Submissions, that "if cost of service is to be used as a tool to design rates, then fairness requires that the same cost of service methodology apply to all rates" and "[f]airness requires that all rates, that are designed based on cost of service, use the same cost of service methodology". While 65 MW is the load characteristic referenced in the Settlement Agreement and used in the cost-of-service studies in the 2026-2027 GRA, the Board finds that setting PHP's forecast 3CP demand at 65 MW is also the most consistent with NS Power's currently approved cost-of-service methodology.

[64] Mr. Bowman's recommendation to use 120 MW is based on a theoretical high load factor profile. The Board finds it is unlikely that PHP's actual load during the winter system peaks in 2027 (which the Board considers to be the appropriate test year for the purpose of setting the initial ELID Tariff rate) would be at that level.

[65] Both NS Power and PHP considered that allocating demand-related costs to PHP using an assumed 120 MW of demand at 3CP likely over-allocates costs to PHP. Load at that level is not supported by the historical information provided in Undertakings U-2 and U-3 or IG IR-30(a) (particularly when considering the response to Undertaking U-20).

[66] The evidence about PHP's various and preferred operating modes reviewed by the Industrial Group in its Closing Submissions does suggest that, without the influence of active dispatch, PHP's 3CP load could be higher than 65 MW and could even be as high as 120 MW. But this is not necessarily the case. As PHP noted, the likelihood that it would be operating at those levels at the time of all three system peaks is probably lower, particularly when considered in the context of the evidence PHP cited around the extent of its downtime in the winter months (e.g., Exhibit N-51).

[67] Moreover, the current cost-of-service methodology focuses on expected actual load on the system when the winter peaks occur as the driver of system costs. In this regard, the Industrial Group's primary concern is that PHP would be overcompensated if demand values that have been influenced by active dispatch are used because they are likely to be lower than what would be the case in the absence of active dispatch, and PHP has already been compensated for reducing its demand during system peaks through the active dispatch mechanism.

[68] While the Board appreciates that Mr. Bowman's approach is consistent with the high load factor customer baseline load assumption used to value credits under the Dispatchable Rider element of the proposed ELID Tariff, the Board does not agree that the approach to setting the demand determinant and valuing the Dispatchable Rider credit

must be the same. As discussed already, that approach does not lead to allocating demand-related costs based on the load actually expected to be on the system at the time of the winter peaks under NS Power's current cost-of-service approach. Additionally, the Board agrees with PHP that the demand charge and the Dispatchable Rider credit deal with distinct costs. As such the Board does not accept that using different approaches leads to double compensation or receiving compensation twice for the same service. The demand charge is intended to recover fixed demand costs while the Dispatchable Rider provides a credit relating to variable energy costs.

[69] Although PHP's support shifted away from using 8 MW to allocate demand-related costs in its Closing Submissions, the Board finds this would be inappropriate to use in the proposed ELID Tariff. As noted above, the historical information and other evidence in this proceeding around PHP's operating modes suggests the amount of load expected to be on the system at the time of the winter peaks is likely to be higher than that amount. The Board also finds it would be inappropriate to exclude the part of any 3CP demand that is above PHP's 8 MW level of firm demand. That is not consistent with how interruptible load is treated for other customer classes.

[70] Both NS Power and PHP now support, to differing degrees, using 65 MW to allocate demand related costs (PHP's support is contingent on the value of the interruptible credit). However, there is an important difference in how they get there. This is highlighted by the different approaches suggested for allocating demand-related costs in NS Power's next GRA. PHP proposes to use average actual metered peak load over a representative period, adjusted for any anticipated changes in load, to allocate demand-related costs. NS Power said it may not be able to rely on historical or purely forecast

figures at the time of system peak like it does for other customer classes. It said judgment would be needed to determine the "right number" that provides an "appropriate allocation" and a "fair allocation of costs across classes".

[71] PHP's approach is more closely aligned with NS Power's approved cost-of-service methodology. Indeed, in its Closing Submissions, NS Power suggested that the cost-of-service methodology was inappropriate for PHP and asserted it was necessary to "look beyond the actual 3CP number…to make sure that it produces a fair outcome".

[72] As mentioned already, InterGroup noted there are alternative cost allocation models that could address this problem. Given the fact that NS Power just completed a review of its cost-of-service methodology for its 2026-2027 GRA, NS Power's statement that its model does not appropriately allocate costs to its largest customer is very troubling. While PHP has been on a below-the-line rate for a number of years, when the cost-of-service model was under review, it was anticipated that PHP could very well transition to an above-the-line rate (as is proposed in this proceeding). In the Board's view, this problem should have been anticipated and addressed. As the Board expressed in the *2026-2027 GRA Decision*, it is concerned that NS Power failed to put appropriate effort into resolving important issues in favour of the "expediency of bringing forward a consensus position to support its general rate application".

[73] The Board recognizes that the application of the 3CP model is relatively simple and accounts for the highly winter peaking nature of the system. At the same time, a 12CP model, which considers the system peaks in every month of the year, might better reflect ongoing use of the electrical grid, but de-emphasizes use during the winter peaks that may be more strongly cost causative. However, there are likely hybrid or other

approaches that provide for a more appropriate recognition of both ongoing system use by large highly interruptible loads as well as the use of the system at its annual peaks. These should be explored. They are likely to provide a more appropriate way to allocate demand-related costs to PHP that would then be consistent with other classes. They may also be less subject to the significant degree of judgment or subjectivity that NS Power is proposing, which could lead to perennial battles over the “appropriate” level of demand. These alternative approaches may be more complex but given the complexity of PHP’s rate design and load highlighted by NS Power, a more complex allocation method is likely warranted.

[74] As noted above, the Board finds that PHP’s forecast 3CP demand will be set at 65 MW for the purposes of service under the ELID Tariff beginning January 1, 2027. However, rather than set out how PHP’s level of demand should be determined in NS Power’s next GRA, the Board directs NS Power to engage with interested parties in a further review of its cost-of-service methodology and bring an application to the Board that can be determined before NS Power’s next GRA. As NS Power has just completed such an exercise, this is an unfortunate outcome, but it is a necessary one given NS Power’s acknowledgement that its existing approved 3CP methodology is not appropriate for all its customers.

[75] The Board notes that, as a result of the Settlement Agreement relating to NS Power’s last GRA and the Board’s decision in that matter, it was anticipated that NS Power would be bringing forward another application to the Board this year to address the minimum system versus basic customer method for allocating distribution system costs, as well as other cost-of-service concerns raised by Synapse (aspects of which

included addressing moving away from the 3CP methodology). Given the direction above, it would be appropriate for these matters to be addressed together in one application before the Board, which may be later than the end of this year. However, to be clear, an application addressing all these issues must be brought early enough that it can be decided before NS Power's next GRA. If not, the processing of that application might be delayed if these important cost-of-service issues have not been settled by that time.

2.4 Energy Charge

[76] The proposed Energy Charge under the ELID Tariff is 9.977 cents per kWh for 2026 and 11.240 cents per kWh for 2027. Those rates were determined from NS Power's COSS model during the 2026-2027 GRA, in which PHP was treated as an above-the-line customer. 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. The reduction in 2027 is attributed to the forecast displacement of NS Power electricity supply by energy from the Goose Harbour Lake Wind Farm under a Power Purchase Agreement.

[77] The energy charges proposed for 2026 and 2027 apply to energy supplied to PHP in excess of the "Subject Energy Amount" deemed provided through the Power Sales Agreement associated with the wind farm. Under this structure, the Subject Energy Amount is deemed to be delivered to the facility before any regulated tariff energy is supplied by NS Power.

[78] Goose Harbour Lake Wind Farm will be connected to the Nova Scotia grid but not directly connected to the PHP mill. Through the Power Purchase Agreement in place with NS Power issued by the Province, PHP will track the energy produced by the wind facility. Throughout the year the energy consumed by the mill will be netted off with

the energy produced by the wind facility such that PHP's final bill for the year from NS Power will be the net of mill energy minus the wind energy, multiplied by the NS Power tariff per MWh energy price, plus or minus any associated additional cost or credit components of the applicable tariff.

[79] In its evidence, PHP expressed concern that the 2026 and 2027 forecast energy requirements used by NS Power in calculating the ELID Tariff do not reflect the most updated assumptions. PHP's annual forecast energy requirements based on the most recent information provided to NS Power are lower than what was provided for modelling purposes for the 2026-2027 GRA. For 2026, PHP provided a forecast of just over 774,000 MWh. An identical forecast was provided for 2027. Also, PHP's evidence noted the current forecast of generation from the Goose Harbour Lake Wind Farm as 154,610 MWh in 2026 and 507,400 MWh in 2027. These numbers were updated again in undertaking responses.

[80] Evidence filed by PHP's consultant, Brubaker, stated:

> We would recommend that the proposed ELID tariff reflect the current forecast energy sales as provided in PHP's direct evidence. These forecasted energy sales figures more accurately reflect the likely energy sales to PHP in the applicable years. Aligning the tariff with current usage assumptions ensures that energy cost allocations and revenues accurately reflect PHP's actual cost of service. By reflecting the total system energy usage upfront, this establishes more accurate per-unit rates.
>
> [Exhibit N-2, p. 28]

[81] Bates White noted a concern with NS Power's determination of the Energy Charges. Bates White's review of the application concluded that the net PHP load used in deriving the ELID Energy Charge is too high, and the resulting Energy Charge rates are consequently too low. Bates White stated:

> A. Generally speaking, the lower PHP's load in the COSS model, the higher PHP's Energy Charge in ¢/kWh terms, but the lower the total energy payment by PHP to NSPI. The Energy Charge increases in ¢/kWh terms when PHP load in the model is lower

> because the Energy Charge includes the allocation of some fixed costs in addition to fuel costs.
>
> …Focusing on 2027 for simplicity, NSPI incorporated gross PHP load of 811 GWh, while PHP has advanced an updated estimate for its load in 2027 of 774 GWh, a reduction of 37 GWh. More significantly, NSPI applied a projected output for Goose Harbour that assumes a facility installed capacity of 130.5 MW, while the reported planned facility capacity is 168 MW, the maximum amount accommodated under the PPA and PSA. Goose Harbour's planned capacity is thus approximately 29% greater than represented in the COSS and, under the reasonable assumption that expected output scales with capacity, the energy from Goose Harbour would be 653 GWh rather than the modeled 507 GWh. Combining both the lower projected PHP gross load, and the higher expected output from Goose Harbour, the net PHP load incorporated in the COSS would more appropriately be 121 GWh rather than the 304 GWh applied in determining the proposed ELID Energy Charge rates.
>
> A. In most direct terms, if PHP's net load in 2027 subject to the Energy Charge is 121 GWh rather than 304 GWh, a 60% reduction, the revenue from PHP to NSPI would be lower by the same 60%, or approximately $21 million, calculated at the proposed 2027 tariff rate of 11.24 ¢/kWh. The cost to serve PHP load would also be lower, but not in direct proportion to the net load reduction. As noted above, if a lower net load for PHP were used in the COSS, the resulting ELID Energy Charge rate would be higher, because some costs captured in the Energy Charge do not change in exact proportion to energy usage. By applying a net load for PHP that is too high, the resulting Energy Charge rates proposed in NSPI's Application are too low, increasing the likelihood that PHP does not contribute appropriately to system costs. In the absence of any mechanism to correct for such a shortfall in cost contribution, other FAM customers would be exposed to making up the difference. [Footnotes omitted]
>
> [Exhibit N-20, pp.14-15]

[82] Bates White recommended that the Board not approve the ELID Energy Charge as proposed. They recommended that NS Power be required to update the COSS model to better reflect likely PHP net load, capturing both updates to expected PHP gross load and the likely capacity output of 168 MW from the Goose Harbour Lake Wind Farm.

[83] Bates White also noted that it would not be appropriate to modify other components of the ELID Tariff that would lower costs to PHP, such as reducing PHP's coincident demand for interruptible load applied in the COSS, without also fully updating the model with a more realistic estimate of PHP net load. Otherwise, the potential for under-recovery of embedded costs from PHP would be exacerbated. Bates White further stated that setting the Energy Charge based on a more realistic estimate of PHP net load

would appropriately reduce the extent to which FAM customers bear the risk of under-recovering costs from PHP.

[84] The Small Business Advocate noted that the Energy Charges set for 2026 and 2027 are reasonable and expressed support for that aspect of the proposed ELID Tariff application.

[85] NS Power noted that Bates White correctly concluded that using a higher forecast energy compared to lower actual energy consumption will produce lower fixed cost recovery because a portion of energy-related costs per the cost of service are fixed. In addition, NS Power noted that PHP is also of the view that the cost of service should be updated for lower energy forecast amounts.

[86] NS Power agreed with Bates White's conclusion that its recommended updates are required if other elements of the Settlement Agreement are recast. However, in stating that the nature of the rate-setting process for above-the-line tariffs is reliant on forecasts at a point in time, it submitted that for this application, the "point in time" was when the tariff costing was examined as part of the cost-of-service development process, prior to completion of the Settlement Agreement, and was affirmed through the Settlement Agreement. NS Power stated that altering certain agreed-upon elements of the Settlement Agreement risks unwinding all Settlement Agreement agreed-upon elements and fundamentally resetting this process.

2.4.1 Findings

[87] Although the Small Business Advocate supports the Energy Charge proposed in this application for 2026 and 2027, Bates White does not recommend Board approval of the ELID Energy Charge as proposed. Furthermore, Bates White, PHP, and its consultant were of the view that the cost of service should be updated for lower energy

forecast amounts. In expressing that view, Bates White concluded that its recommended updates are required if other elements of the Settlement Agreement are recast.

[88] In response, NS Power agreed with Bates White's conclusion but stated that the update should have been done during the cost-of-service development process in the GRA, prior to completion of the Settlement Agreement. NS Power cautioned that altering certain agreed-upon elements of the Settlement Agreement risks unwinding all Settlement Agreement agreed-upon elements.

[89] PHP submitted that two approaches for setting its energy assumptions were justifiable. The first was to maintain the assumed consumption of 304.3 GWh from the 2026-2027 GRA COSS. This position was based, in part, on NS Power's evidence that it would be difficult to adjust the forecast for PHP load assumptions in isolation. PHP said the second justifiable approach was to update the net load forecast based on the information contained in the responses to Undertakings U-4 and U-2. This would result in a net revised energy assumption of 252.1 GWh.

[90] Where there are two reasonable justifications that have evidentiary support, as previously discussed, the Settlement Agreement can assist the Board in coming to a determination. This would be different than the situation with the value of the Interruptible Rider credit discussed later, where there was no evidence to support the proposed figure. It is also different from the sharing mechanism the Board has ordered for the Dispatchable Rider credit. In that case, the Board has determined the potential for over-compensation favoured a result where there was a sharing mechanism, although heavily weighted towards PHP. In any event, the Board notes there is merit in aligning the ELID Tariff with current PHP usage assumptions, but considers the risks associated with updating certain

elements of the load forecast in the COSS outside of a GRA to be of greater concern. The Board approves the Energy Charges for 2027 as proposed in the ELID Tariff application.

2.5 Interruptible Rider

[91] Under the Interruptible Rider, NS Power would be authorized to request that PHP reduce its interruptible load by an amount required by the utility within 10 minutes of such a request. This type of service allows NS Power to better manage its load in times of very high demand or other resource constraints to avoid system disruptions that could otherwise occur. The notice would specify the portion of PHP's load that is firm and the portion that is available for interruption. In this case, NS Power based the credit on PHP having 8 MW of firm power and 57 MW of interruptible power based on the 3CP value of 65 MW used in the Demand Charge calculation. If PHP failed to honour the interruption request, it would be subject to monetary penalties. There is a limit to the extent of interruption that NS Power could demand (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). The proposed Interruptible Rider service provisions adopt most of the terms found in a similar rider in the Large Industrial Interruptible Rider (LIIR) Tariff, along with some modifications taken from the ELIADC Tariff interruptible service provisions.

[92] Under the proposed ELID Interruptible Rider, PHP would receive a credit or reduction in its demand charge of $7.638 per kVA and $7.667 per kVA of interruptible service for 2026 and 2027, respectively. These figures were based on the Settlement Agreement stipulating that for 2026 and 2027 the credit would be set at the dollar value of the LIIR customer interruptible credit. The 2026 interruptible credit is no longer relevant. NS Power highlighted that the value of the credit derived from the Settlement Agreement

was significantly lower than if the company had used its established practice to derive the PHP interruptible credit. NS Power said the established practice would calculate the ELID interruptible credit at $13.107 per kVA for 2027.

[93] The ELID Interruptible Rider also has a credit related to priority interruptible service. NS Power proposed a value of approximately $500,000 for this service whereby PHP would be second in the queue for interruption amongst customers under other rates with interruptible service (after customers under the Generation Replacement Load Following Tariff). NS Power's initial analysis indicated the main direct benefit of this service was to reduce the risk of interruption to other customers. While NS Power acknowledged more analysis would be required, it said the $500,000 figure was justifiable. The figure is derived from comments the Board made when approving an interruptible credit for another tariff in Matter M05550. In that matter the Board found that priority interruptibility for large industrial customers had value because it allowed NS Power to quickly shed a significant amount of load for immediate pressure relief on the grid. With little evidence about how to value this type of credit, the Board accepted a compromise figure of 15%. NS Power used 10% in the ELID Tariff.

2.5.1 Relationship Between the Interruptible Rider and the Dispatchable Rider

[94] A threshold issue raised by the Industrial Group is that the Interruptible Rider credit should be assigned little or no value. The rationale was that the experience under the ELIADC showed that, because of the dispatchability process under that tariff, PHP had already been dispatched down nearly to its house load of 8 MW to 20 MW when other interruptible customers were called upon to interrupt during periods of potential constraints on the grid. This was based on an analysis conducted by Mr. Bowman, as

well as the IR Responses and Undertakings filed in this proceeding. The Industrial Group said that since the proposed ELID Tariff also had a dispatchability component, the Interruptible Rider credit should be based on the power that was genuinely expected to be available for interruption during system constraint episodes. This amount was expected to be very low, and providing a credit for the interruptibility of the same energy that had already been dispatched down amounted to a double recovery. Because of the low amount of potential energy available for interruption under this analysis, the Industrial Group said there was no basis for a priority credit. The Consumer Advocate questioned the value of the Interruptible Rider credit based on the foregoing analysis, but because of his interpretation of the Settlement Agreement, did not strenuously advance this position.

[95] PHP countered that the Dispatchable Rider and the Interruptible Rider are two distinct services. NS Power calls upon the Dispatchable Rider based on short-term price signals related to the cost of fuel and the optimal generation blend. The Dispatchable Rider is, therefore, based and priced on operating cost savings. PHP submitted that the Interruptible Rider credit provides NS Power and its ratepayers long-term capital investment savings. PHP submitted that the level of planning reserves required for the stability of the bulk electrical system by the Northeast Power Coordinating Council (NPCC) and the North American Electricity Reliability Corporation (NERC) is derived from the firm load NS Power is expected to serve. PHP says NS Power's witnesses confirmed only the interruptible load is not considered firm. Without the Interruptible Rider, PHP says NS Power would have to build expensive generation facilities to meet planning reserves because dispatchable energy is considered firm. PHP submitted that although, historically, it may already have been dispatched down, this is not relevant because there

are two distinct services even if used or available for the same constraint event. As well, PHP pointed to the different mechanisms related to the control of power dispatch, where PHP can choose whether to dispatch down based on business considerations, while the interruptible call is mandatory and subject to more stringent penalties.

[96] NS Power essentially agreed with PHP on this issue. NS Power said that while the interruptible service helps with short-term planning in emergency situations, the value of this service is not in individual interruptions but in the availability of interruption for resource planning purposes. NS Power said that NPCC's resource adequacy criteria require planning coordinators and resource planners to assess reliability against the risk of curtailing firm load. NS Power testified that load subject to dispatch is still considered firm load while load subject to interruption is not. This impacts the level of generation required to meet resource adequacy criteria. NS Power also addressed the different processes and penalties available under the Dispatchable Rider and the Interruptible Rider, as well as the importance of dispatchable power as a regular planning tool when integrating large amounts of intermittent renewable wind generation.

2.5.1.1 Findings

[97] The Board agrees with NS Power and PHP that the dispatchable service and the interruptible service are two distinct services and that PHP should be compensated for providing both. The dispatchable service is used throughout the year. It provides NS Power with a great deal of control over PHP's load in a planned manner. Based on forecasts, NS Power asks PHP to adjust its load on a regular basis to try and achieve an optimal power generation mix. This provides NS Power with flexibility when integrating intermittent wind resources. It can also result in cost savings. The cost savings aspect and how it should be allocated are discussed separately in this decision. While NS

Power and PHP have cooperated on dispatchable energy under the ELIADC, it is still a voluntary service in the sense that PHP can decline to ramp down when requested to do so by NS Power. This would ordinarily be for business production reasons. Conceptually, PHP's financial loss, if it does not ramp down to NS Power's requested level, is that it would not recover, under the Dispatchable Rider, any operating cost savings that the request might have generated. Interruptible service is completely different. Instead of ramping up or down in a planned and coordinated manner over the course of the year, interruptible service is designed to provide relief for short-term emergencies when load constraints threaten the power grid's stability. Interruptions usually occur when there are unusually high electricity demands caused by extreme cold, when there are failures or potential failures in generation facilities, or along the bulk transmission lines. The demand to ramp down is on 10 minutes notice. If PHP failed to abide by the interruption request, not only would it have to pay an additional amount for the energy consumed during the event, it would also be liable for a significant performance penalty.

[98] The credit available to PHP under the Interruptible Rider is calculated on a completely different basis than the one available under the Dispatchable Rider. It attempts to capture the incremental cost savings resulting from there being less generation capital costs in rate base because PHP's interruptible load does not count as firm load when addressing the NPCC and NERC resource adequacy criteria. While NPCC and NERC were discussed somewhat interchangeably in the evidence, the Board notes it is NERC who develops the most applicable reliability criteria. NPCC has some regional standards or guidelines. Both become effective in Nova Scotia upon Board approval. Through memorandums of understanding, NPCC audits these standards on behalf of the Board.

In any event, the point is that once approved, resource adequacy compliance is mandatory and not having to account for PHP's interruptible load in the reserve planning exercise, because it is not considered firm load, has a value separate and apart from the dispatchable nature of PHP's load. The cost savings are assessed in the COSS in relation to the demand charge and form the basis for the interruptible credit's value.

[99] The Board accepts as a fact that during all 27 interruption events that occurred between 2020 and 2025, PHP was only interrupted once. The Board further accepts as a fact that in almost all instances where other customers were interrupted during this period (23 of 27 incidents), PHP was at or near its house load of 8 MW to 20 MW, having already been dispatched down to these levels before an interruption event was called by NS Power. The detailed evidence elicited by the Industrial Group fully supports this conclusion and this was not challenged in any meaningful way by PHP or NS Power. Mr. Bowman recommends that in this scenario, the Board should first establish a baseline of PHP energy consumption, then subtract the amount of energy which had historically already been dispatched down to arrive at an amount of energy available for interruption. Otherwise, according to Mr. Bowman, PHP is being compensated for the same energy ramp down twice. The Industrial Group incorporated this recommendation in its detailed submissions.

[100] The Board does not accept this recommendation because, as discussed above, two distinct services are being provided and the credits to PHP are based on two different cost-causation principles. The Board understands that in the past, and presumably in the future, PHP may well already have been ramped down when an interruption event occurs. It is also possible that an interruption call for PHP load would

occur in an emergency event even if the power is already dispatched down to ensure the emergency protocols and penalties are available for such an event. That said, the main value of the interruptible credit lies elsewhere, in the capital cost savings that it can generate in the resource adequacy planning exercise.

2.5.2 What is the Value of the Interruptible Rider Credit?

[101] A second major area of dispute about the Interruptible Rider is the value of the associated credit. NS Power says this was established by the Settlement Agreement. NS Power simply transposed the dollar value of the LIIR interruptible credit into the ELID Interruptible Rider. NS Power acknowledged that this amount does not reflect what the credit would have been if the established practice had been used to calculate the PHP credit. NS Power submitted this can be revisited during the next GRA. The Small Business Advocate took essentially the same position. The Industrial Group did not provide any substantive arguments on the value of the interruptible credit but indicated it was not opposed to using NS Power's standard methodology. If its argument on how to establish the amount of energy available for interruption is accepted, the value of the credit would only be applied to a small amount of energy.

[102] Initially, PHP's primary position was that there was no need for an interruptible credit if PHP's load for the demand charge was set at 8 MW. This would mean there would be no firm load to interrupt and no corresponding need for an interruptible credit. PHP's alternative position was that if the Board determined the load for the demand charge should be more than the 8 MW, the interruptible credit had to be established based on NS Power's established methodology. Otherwise, PHP said the credit would not reflect the true cost savings to NS Power because PHP's load above the 8 MW was interruptible. PHP says this would amount to cross-subsidization benefitting

other ratepayers at PHP's expense and would be manifestly unfair to PHP. At its heart, PHP says the *Public Utilities Act*, RSNS 1989, c 380, and the applicable public utility principles require that interruptible customers be treated in the same manner. In its Closing Submissions, PHP indicated that establishing the demand charge at 65 MW had a basis in the evidence and was acceptable provided the value of the interruptible credit was established in accordance with NS Power's established methodology.

2.5.2.1 Findings

[103] There is no evidentiary support for the $7.667 per kVA interruptible credit. NS Power acknowledges that it is not calculated in the same way as the credit for its other interruptible customers and that it will likely have to be adjusted in the next GRA. The parties who support it, including NS Power, rely entirely on the PHP Treatment Terms of the Settlement Agreement. Given the Board's comments on the more limited weight it will give the Settlement Agreement, it would require some evidence supporting the figure before simply adopting it. Treating customers in the same rate class differently would likely lead to a finding of unjust discrimination. On the other hand, the Board does not accept that a different treatment for a component of a rate that appears in two separate rate classes automatically results in a tariff that is unjustly discriminatory. The components in one rate class may operate together differently than the components in another, which could potentially justify the differing approach in the two tariffs.

[104] The ELID Tariff is no doubt different than the LIIR Tariff, most notably because of the Dispatchable Rider. However, there is no basis for tying the chosen value of the Interruptible Rider credit proposed by NS Power to this distinction. The Interruptible Rider credit and the Dispatchable Rider credit relate to two different services that are priced in two different ways. The Board finds that the basis for the Interruptible Rider

credit calculation for PHP should be "…the amount of PHP interruptible load that forms part of the billing determinants used by NS Power to allocate demand costs to PHP in the cost of service, and which allows NS Power to avoid the need to build or acquire more peak generation". That amount is 57 MW based on the three peak coincident methodology discussed in the demand charge part of this decision.

[105] The Board further agrees with PHP that it should be compensated for the full 57 MW. Otherwise, any remaining load that is not included in the calculation would be costed in the COSS in the same way as if it was firm. The LIIR customer class does not have the same billing determinants as PHP. As Hayitboy Mahmudov of InterGroup acknowledged, it is not reasonable to develop rates for a distinct customer class using the billing determinants of an entirely different class. To transpose the calculated credit under the LIIR Tariff into the ELID Tariff is not fair to PHP. Unlike the LIIR customers, it does not compensate PHP for the avoided peaker capital cost impacts of its interruptible load. This is what NS Power's standard interruptible credit calculation methodology, which has been used for decades, seeks to accomplish.

[106] The Board finds that assigning the numerical value of the LIIR interruptible credit to PHP is not supported by any evidence, it is contrary to public utility law principles about fair allocation of costs, and, as it impacts a major component of the ELID Tariff, it has an unjustly discriminatory impact. Regardless of the Settlement Agreement, the Board will not approve NS Power's proposed rate of $7.667 per kVA of interruptible service for 2027. The Board accepts NS Power's evidence that the standard methodology results in an interruptible credit of $13.107 per kVA of interruptible service. The interruptible service is established at 57 MW.

2.5.3 Priority Interruptible Credit

[107] NS Power's proposed Priority Interruptible credit was not supported by any other party, except perhaps PHP in its evidence. However, in its Closing Submissions, PHP agreed to forego this credit, meaning it would be in the same queue as other interruptible customers. In NS Power's Reply Submissions, the utility continued to maintain that being able to interrupt PHP on a priority basis has a value. The value of interrupting PHP in priority to all other interruptible customers, except customers under the Generation Replacement and Load Following Tariff, cannot be ascertained from the record. The value of priority interruptions is primarily based on being able to shed large loads in emergency system constraints situations. Therefore, cost causation issues are completely different than for the Interruptible Rider credit itself. The credit for priority interruptions is not based on peaker capital costs. Historically, PHP is already dispatched down in times of system constraints. Based on this historical record, there is really no basis to determine that NS Power will gain any benefit from being able to interrupt PHP in priority to other interruptible customers. Therefore, the Board agrees that the Priority Interruption credit should be eliminated from the ELID Tariff.

2.6 Dispatchable Rider

[108] The proposed ELID Tariff incudes a mandatory Dispatchable Rider. Under this rider, NS Power can manage PHP's load in response to system conditions. The primary aim of the Dispatchable Rider is not to reduce load at system peak, but to optimize PHP's load on an ongoing basis to reduce overall system costs.

[109] Importantly, PHP's obligation to follow dispatch directions from NS Power is voluntary. However, PHP is financially motivated to respond to these directions because the tariff compensates it for the value of its load flexibility by crediting it with the

system savings it produces. The terms and conditions of this arrangement will be set out in operating procedures to be developed by NS Power and PHP.

[110] The foundation for this arrangement is the assumption that, without the Dispatchable Rider, PHP would be incented to run its plant in a way that optimizes its own operations and electricity use. Typically, this would mean it would operate at a high load factor. NS Power's application stated that the rider's structure shields other customers from the significant incremental cost impacts that PHP, the system's largest customer, could have on electricity system customers, if PHP were not incented to operate in a way that optimizes overall electricity system costs.

[111] Under the rider, the system savings produced by dispatching PHP's load away from its assumed high load factor baseline will be determined at the end of the year. The amount of the savings is the difference between the actual annual system costs and the calculated system costs if PHP operated at its assumed customer baseline (the theoretical high load factor profile). This counterfactual assumption would incorporate PHP's actual load in the year, the dates and durations of PHP's major scheduled maintenance periods and other factors.

[112] The methodology proposed to evaluate the Dispatchable Rider benefit under the ELID Tariff was further described in NS Power's response to Undertaking U-8.

2.6.1 The Dispatchable Rider Credit

[113] An initial analysis undertaken by NS Power based on 2025 data estimated that if PHP's dispatch had been 100% optimized, the service provided under the Dispatchable Rider would have produced system savings of approximately $7 to $11 million for the year. However, NS Power surmised that this level of savings would be challenging to achieve because system conditions, PHP's production constraints or

requirements, and other factors would sometimes conflict with optimal load dispatch. NS Power said the value created by the optimized dispatch of PHP's load each year should be fully credited to PHP because PHP's energy and demand will be priced on an embedded cost basis, the cost of providing the service was borne by PHP, and the overall performance of the mechanism is based on PHP's performance.

[114] Brubaker compared the credit under the proposed Dispatchable Rider to NS Power's existing credit for interruptible load:

> …[S]ound rate design principles dictate that customer classes possessing operational flexibility should be properly incentivized to utilize that flexibility to lower total system costs. This concept is perfectly demonstrated by the standard Interruptible Credit; the LIIR class receives 100% of its capacity benefit because all customer classes ultimately benefit from the operational flexibility and avoided generation costs that the LIIR class provides. Forcing the LIIR class to share this specific credit would dilute their operational incentive to interrupt, thereby increasing peak demand risks and driving up total system capacity costs for all ratepayers. The proposed DR operates in precisely the same manner. While PHP receives the direct credits for its performance, all other customer classes on the system will simultaneously benefit from the unique Active Demand Control flexibility provided by PHP's operations, which works to lower average Fuel Adjustment Mechanism ("FAM") costs across the entire grid.
>
> [Exhibit N-36, p. 10]

[115] NS Power proposes to include credits paid to PHP under the Dispatchable Rider as fuel adjustment mechanism costs recovered from all FAM customers. NS Power's fuel forecast in its 2026-2027 GRA assumed that PHP's load would be optimized for the system, but it did not account for the payment of Dispatchable Rider credits to PHP. As such, NS Power's current base cost of fuel understates the impact of the proposed ELID Tariff and would be under-recovering fuel costs. Going forward, it is NS Power's intention to forecast its fuel costs assuming the theoretical levelized customer baseline load for PHP. Therefore, with all else equal, when fuels costs are saved because of the optimization of PHP's load, actual fuel costs would be lower than forecast but offset

by the payment of credits to PHP, leaving FAM customers in a more or less neutral position relative the base cost of fuel forecast.

[116] Bates White had concerns about the proposed Dispatchable Rider credit. It summarized its recommendation about the rider as follows:

> **Q. What is your recommendation regarding the DR credit?**
>
> A. We do not recommend that the Board approve the DR credit as proposed. To be reasonable, at least two things must be true: (1) any payments to PHP from FAM customers under the DR credit must be demonstrably tied to PHP deciding to shift load due to energy prices and (2) that FAM customers not be at risk of providing any compensation to PHP in hours where no load-shifting activity due to energy prices occurred. It may be that, with additional elaboration, revisions, reporting requirements, and verifiability guardrails, the mechanism may achieve these objectives, but as proposed, it is our view that the DR credit is too vague, uncertain, unverifiable, and at risk of failing to match rider payments to load-shifting service to be recommendable for approval.
>
> [Exhibit N-20, p. 28]

[117] Although it noted that Bates White had indicated that the mechanism may be satisfactory with additional elaboration, revisions, reporting requirements, and verifiability guardrails, Brubaker disagreed with what it considered to be a "flat rejection" of the Dispatchable Rider credit by Bates White. Brubaker said, "[r]ather than entirely rejecting a vital operational tool that eliminates high-cost marginal energy spikes for the benefit of the entire grid, the Board should approve the DR credit framework subject to collaborative reporting enhancements agreed to by NS Power and PHP".

[118] NS Power cautioned against imposing extreme levels of precision on the ELID Tariff or any other customer tariff. It went on to state:

> …Building on this, the assumed flat customer profile, while likely to be imperfect, provides a reasonable foundation upon which to measure load shift. Moreover, the development of the updated customer baseline (CBL) at year-end with the foundation of actual customer load, actual system profile, actual fuel information, etc. is a significant improvement on the ELIADC Tariff in terms of transparency and simplicity.
>
> As is likely to be the case for any large customer complex tariff, the ELID Tariff will not be perfect. While the high load factor base may offer some benefit to PHP in terms of a favourable starting point it also offers benefits to other customers in that, should PHP choose to operate during high load periods, under the DR construct the incremental cost

> of this compared to the CBL will be borne by PHP, not other customers. As experience with the tariff, in general, and this element in particular is developed, it may be this will be an area for further review and refinement.
>
> While BW has identified a number of potential concerns with the DR construct, it has not proposed an alternative that would address PHP's unique operational requirements while preserving the dispatchability benefits underlying the proposed DR service. Thus, while BW concludes "[i]t may be that, with additional elaboration, revisions, reporting requirements, and verifiability guardrails, the mechanism may achieve these objectives," the Company submits that seeking this level of assurance in advance of both a Board-approved tariff and a subscribing customer, is premature. It also ignores that implementation challenges are likely to occur with most new tariffs and that the operation and performance of this Tariff remains subject to FAM audits and ongoing regulatory scrutiny. [Footnote omitted]
>
> [Exhibit N-38, p. 19]

[119] The first of Bates White's concerns was that PHP's incentive to follow dispatch directions would be dampened because PHP lacked visibility into the savings that would be produced by shifting its load when the decision to do that needed to be made. PHP countered this in its rebuttal evidence, stating:

> Our prior and current practice under the ELIADC is to follow NS Power's directions when technically possible, with the exception of when for commercial purposes we have decided to run through their request, in which case we are responsible for any additional costs incurred. PHP follows MW dispatch schedules, not interpreting price signals and "deciding to shift load", that are the result of its electricity consumption timing being directly integrated within NS Power's economic dispatch optimization tools. Essentially our goal has been to follow NSPI's schedule such as to reduce our energy consumption in high cost periods and utilize more energy in lower cost periods. This has been, and will continue under the ELID to be, why we would shift our load. If we fail to shift our load from time to time to lower cost hours under the ELID we will simply reduce the potential for a larger credit.
>
> [Exhibit N-37, p. 6]

[120] Bates White's second concern was that PHP's load was not predictable enough to determine how it would have operated over an entire year under the counterfactual customer baseline scenario. However, PHP noted in its rebuttal evidence that while its orderbook used to be dominated by seasonal demand, new product development has significantly changed its paper demand to a more regular monthly profile. It said its load is, for the most part, predictable from hour to hour, with occasional operation failures, similar to power generators.

[121] Bates White's third concern was that PHP's load would not likely be levelized if there was no Dispatchable Rider. PHP disagreed with this. Its rebuttal evidence said that, like all other energy intensive industrial producers, it continuously seeks the most efficient operating modes, desiring less idle time given its fixed costs. PHP also stated that its assets, which include large synchronous motors, "are best kept running continuously because starting them causes very high electrical currents and mechanical stresses that can shorten equipment life" and "[c]ontinuous operation also reduces thermal cycling, improves reliability, and can help maintain the plant's power factor".

[122] Bates White's fourth concern was that NS Power has too much discretion in calculating the credit, making it difficult or impossible to verify. Responding to questions from Board Counsel at the hearing, NS Power's witnesses suggested there was actually little discretion:

> **Q.** Is there any discretion that's being applied by Nova Scotia Power in conducting that year-end differential calculation?
>
> **A.** (Mowatt) I'd say Nova Scotia Power has access to all of the information that's required. We have the replacement cost, we have PHP's total load, we have the system conditions at that time.
>
> The calculation itself is fairly straightforward. Even the levelizing of PHP's load to mimic that high load factor, that CBL profile, is a formulaic approach. We're using a random seed in order to ensure that there isn't personal bias or any kind of discretion associated with the randomized days to mimic an agnostic -- a customer agnostic to price movements on when they would take those down days.
>
> So it is very much formulaic.
>
> The access to information makes it such that Nova Scotia Power is the only party in a position do the calculation.
>
> Does that make sense, Mr. Mahody?
>
> **Q.** It does, so then back to my question.
>
> What, if any, discretion is Nova Scotia Power utilizing when it's doing those calculations?

> And if the answer's none, it's none.
>
> **A.** (Mowatt) None that I can think of.
>
> [Transcript, September 22, 2026, pp. 45-47]

[123] Bates White's fifth concern was that NS Power did not explain its reasoning for using forward replacement costs to determine the credit under the Dispatchable Rider after NS Power shifted away from that methodology under the ELIADC. At the hearing, NS Power's witnesses explained that the costs allocated to PHP under the ELID Tariff are the embedded costs under the cost-of-service methodology, and that only the Dispatchable Rider credit would use a replacement cost methodology to isolate load-shifting benefits. Further, they said this approach better represents the opportunity costs of using different fuels on the system at different times and provides a more consistent basis to compare actual system costs for the year to the costs of the assumed customer baseline load scenario. At the hearing, Bates White noted that NS Power's testimony allayed some of their concern about this point and made analytical sense. However, Bates White still considered there may, in some limited circumstances, be some risk of experiencing the type of cost distortions that justified the change in methodology under the ELIADC.

[124] Bates White's sixth concern was that the calculation of the credit assumes that any changes between the actual load in the year and the customer baseline load were due to changes actively provided by PHP rather than operational variations that might be entirely independent from system conditions. Mr. Bowman had a similar concern and said it was unlikely that, without the Dispatchable Rider, PHP would operate under a "near-perfectly optimized high load factor", resulting in a risk of excessively crediting PHP and harming other customers.

[125] Mr. Bowman suggested this concern could be addressed by either amending the customer baseline load to make it more representative of expected PHP load or sharing the credit for savings generated by shifting from the theoretical baseline. He said the sharing approach would be simpler to implement and more consistent with current practice under the ELIADC Tariff. While InterGroup stopped short of a specific recommendation to include a sharing mechanism, it said the Board should consider the reasonableness of the Dispatchable Rider savings being fully credited to PHP given the complex interactions of the elements of the proposed tariff and the changes to various elements compared to the ELIADC Tariff.

[126] At the hearing, NS Power agreed that the levelized load assumption for the counterfactual customer baseline is likely favourable to PHP, as it is unlikely that PHP could operate at that optimal customer baseline in the real world. Its actual operations are likely to be somewhat suboptimal, although the degree to which this is the case cannot really be determined. However, NS Power considered that the risk to other customers from PHP's large load operating without any form of dispatch control was greater than the degree of imprecision in the setting of the customer baseline.

[127] In its Closing Submissions, PHP agreed that, in any scenario in the real world, it is likely to operate on a suboptimal basis compared to the optimal levelized load that NS Power would use as part of the Dispatchable Rider credit calculation. It also agreed that this is a favourable assumption to PHP; but how favourable cannot really be determined. PHP also submitted there are significant reliability benefits from the Dispatchable Rider that accrue to customers that are difficult to quantify and are not included in the "energy-only credit calculation".

[128] NS Power, PHP and Brubaker all disagree with the suggestion that there should be a sharing mechanism for the system savings produced through the operation of the Dispatchable Rider. They all raised similar points. They said a sharing mechanism under the ELIADC was appropriate because of the incremental cost basis of that tariff, but inappropriate under the proposed embedded cost-based ELID Tariff. NS Power and Brubaker asserted that imposing a sharing element would see PHP pay more under the ELID Tariff than the cost-of-service methodology prescribed and would undermine PHP's incentive to move its load to produce system savings. On this latter point, PHP said if the benefit from the Dispatchable Rider was not sufficient, it would need to determine whether to offer the service because of the operational and commercial costs it would incur in doing so.

[129] PHP also argued that the existence of unquantified reliability benefits arising from the Dispatchable Rider offset the need for any sharing arrangement. However, the Industrial Group argued that recognizing there was some value for such reliability benefits does not establish that this value offsets the overstatement of the Dispatchable Rider credit because of the favourable assumption of an optimal customer baseline.

[130] The Industrial Group also submitted that the treatment of output from the Goose Harbour Lake Wind Farm provides another justification for sharing the Dispatchable Rider credit. It said:

> …The DR credit is calculated by comparing a hypothetical, high-load-factor CBL against PHP's actual dispatched load, using PHP's full annual load – inclusive of roughly 500 GWh expected to come from Goose Harbour generation. Yet the bills PHP actually pays are calculated net of Goose Harbour output.
>
> The result is that PHP stands to receive DR credit value calculated against its full, load-shaping activity, including shaping that touches energy PHP never purchases from NSPI, while the costs NSPI actually avoids (and the benefit genuinely delivered to other ATL customers) are necessarily smaller and harder to isolate once netted against a banked, non-contemporaneous wind credit. Put simply, if the DR credit is calculated using gross

> consumption while PHP's tariff charges are calculated using net consumption, the credit and the underlying cost responsibility are measured on different bases. Without an adjustment, the resulting credit may exceed the system costs actually avoided.
>
> [Industrial Group, Closing Submissions, p. 13]

[131] In its Reply Submissions, PHP asserted that there was no mismatch or risk of over-crediting. It said the Industrial Group's argument confuses physical load control with commercial billing determinants. PHP asserted that when it curtails operations at NS Power's direction, the system avoids identical marginal costs whether or not the Goose Harbour Lake Wind Farm is generating.

[132] NS Power's testimony at the hearing also suggested that output from the Goose Harbour Lake Wind Farm would not impact the Dispatchable Rider credit:

> **A.** (Mowatt) … The ELID Tariff process for the Dispatchable Rider and what was presented to FAM Small Working Group in Q2 was specifically around PHP's load shifting benefits. So we would take, at the end of the year, PHP's actual load and actual load profile and the prices used to dispatch the system at that time. We would then take the -- PHP's ending year load and levelize that throughout the year, based on the number of down days that they had, so days that they were at house load or 12 megawatts, spread those evenly throughout the months and randomize those throughout the year, and then run that using the same prices that would have went into the dispatch at that time. And you'd get a different dispatch, except for you'd be locking down your wind, hydro unit availability through that period of time, but you'd be letting port ops reoptimize that levelized load profile. And then you compare the two forecasts.
>
> **Q.** And this ---
>
> **A.** (Mowatt) Sorry. And compare actuals to that CBL calculation.
>
> [Transcript, September 21, 2026, pp. 287-288]
>
> …
>
> **Q.** And in determining the mechanism here with the Goose Harbour, how has that been taken into consideration in determining the methodology for the DR credit?
>
> **A.** (Mowatt) So under the credit PHP and Goose Harbour Lake are treated as two separate entities, so we wouldn't evaluate or net off PHP's wind. It's just part of the overall system generation stack in both the actual low PHP load scenario as well as the CBL scenario.

> So to put it more simply, if there's 500 GWh of wind from Goose Harbour Lake at the end of the year it's not netted off. That's just part of the system itself. Does that make sense?
>
> [Transcript, September 21, 2026, pp. 315-316]

2.6.1.1 Findings

[133] NS Power's ability to influence the dispatch of PHP's load under the proposed Dispatchable Rider provides potential system benefits. Much of the concern from the parties in this proceeding about this proposed element of the ELID Tariff related to the valuation of the credit under the rider rather than the concept of active dispatch (which has existed under the ELIADC since 2020).

[134] Bates White distilled the concerns it had in recommending against the approval of the Dispatchable Rider credit to two things it said must be true to make it reasonable: (1) any payments to PHP from FAM customers under the Dispatchable Rider credit must be demonstrably tied to PHP deciding to shift load due to energy prices; and (2) that FAM customers not be at risk of providing any compensation to PHP in hours where no load-shifting activity due to energy prices occurred.

[135] NS Power and PHP concede it is probable that, without the Dispatchable Rider, PHP would not, in fact, operate at the theoretical customer baseline load that is perfectly optimized for the customer, which is the foundation for the Dispatchable Rider credit. PHP's operations would be suboptimal to some degree. It is also possible that some deviations from the proposed counterfactual customer baseline load will occur for reasons other than active responses to dispatch directions from NS Power. These deviations could add to the value of the proposed Dispatchable Rider credit, not because PHP provided any active dispatch service benefitting the system, but simply because of the customer baseline load assumption and happenstance. Mr. Bowman suggested this

could be addressed by either amending the customer baseline load to make it more representative of expected PHP load or sharing the credit for savings generated by shifting from the theoretical baseline.

[136] The Board finds this concern can be addressed by including a sharing mechanism for the system savings. In reaching this conclusion, the Board notes it does not agree with the Industrial Group's submissions that the treatment of output from the Goose Harbour Lake Wind Farm should be a factor that is taken into account when considering whether sharing is appropriate or how much sharing is warranted. The Board accepts NS Power's evidence and PHP's submissions on this point and concludes that output from Goose Harbour Lake is accounted for under both the assessment of actual system costs at the end of the year and the calculation of system costs under the counterfactual customer baseline load and has a neutral impact on the value of the Dispatchable Rider credit.

[137] The Board accepts that PHP will be motivated to follow dispatch directions, as much as possible, to maximize the amount of the credit. The Board notes that actions that it takes that fail to follow dispatch directions could not only result in the loss of the opportunity to earn a credit but could actively reduce the amount of the credit if actual system costs at that time are higher than the calculated system costs under a scenario with the assumed customer baseline load. While extremely unlikely, NS Power's witnesses agreed that, if this occurred consistently over the year, it could result in a negative credit requiring a payment by PHP under the Dispatchable Rider.

[138] The Board also accepts that the Dispatchable Rider should provide reliability benefits that are not captured in the value of the energy-related system savings

that determine the Dispatchable Rider credit. This would tend to offset the extra value likely to be carried in the Dispatchable Rider credit because of deviations from the counterfactual customer baseline load that have nothing to do with actively dispatching the load to produce system savings. As the Industrial Group noted, those reliability benefits are unquantified. But so is the extent to which the Dispatchable Rider credit would be upwardly influenced by savings unrelated to active dispatch.

[139] This uncertainty could justify rejecting the proposed ELID Tariff entirely. However, the Board finds this would result in the loss of an innovative tariff design that could be an important tool for eliminating high-cost marginal energy spikes for the benefit of the entire grid. As discussed later, the factors the Board must consider under the *Energy and Regulatory Boards Act*, SNS 2024, c 2, Sch A, warrant that the Board not take such an approach.

[140] While the Board finds it appropriate that the system savings calculated from the difference between PHP's actual load and its assumed customer baseline load be shared to address this uncertainty, the split is more difficult to determine because there is little objective evidence to support a specific arrangement. The Board finds that the split should be heavily weighted in PHP's favour. This is based on the Board's findings that PHP will be motivated to follow dispatch directions, such that incidental impacts on the Dispatchable Rider credit are more likely to be minimized, and that there are offsetting but unquantified reliability arrangements associated with the Dispatchable Rider. The Board finds that 90% of the calculated system savings should be paid to PHP as a credit under the Dispatchable Rider, with the remaining 10% of the savings shared by FAM customers (including PHP). For clarity, in the extremely unlikely event that the

Dispatchable Rider results in the requirement for a payment by PHP rather than a credit, the sharing mechanism would be reciprocal and only 90% of the additional system costs would be payable.

[141] The Board does not consider that a sharing mechanism at this amount results in PHP paying more than its allocated cost of service. Costs are fully allocated to the ELID Tariff outside of the Dispatchable Rider. The Dispatchable Rider offers PHP the opportunity to offset those fully allocated costs through compensation for providing a distinct service. It is the value of that service that is in issue, not the allocation of costs under NS Power's cost-of-service model.

[142] Likewise, the Board fully accepts the proposition that customers who provide a benefit to the system, like interruptability or system dispatch, should be compensated for the value they create. The Board's determination that a sharing mechanism is appropriate reflects its finding that the credit value is influenced, not only by value that PHP actively creates, but from incidental impacts as well.

[143] Given the uncertainty around the split of this sharing mechanism, it should be reviewed and adjusted or removed if necessary. That said, any adjustment of the sharing mechanism to assess the extent to which the Dispatchable Rider credit reflects only cost savings resulting from the active dispatching of PHP's load would be for the purposes of revising or removing the amount of sharing going forward and should be done in the context of a GRA.

2.6.2 Approval of the Dispatchable Rider Operating Procedures

[144] In their evidence, InterGroup and Mr. Bowman recommended that the operating procedures for the Dispatchable Rider be approved by the Board. Mr. Bowman said core aspects of the tariff design that are important to the value balance, such as

ensuring that NS Power has sufficient control over PHP load at times of acute system constraints, require implementation through this mechanism. In its Closing Submissions, the Industrial Group urged the Board to require the approval of the operating procedures before the tariff takes effect. Alternatively, the Industrial Group suggested the Board should require a defined and transparent process for reviewing the Dispatchable Rider credit calculation at the end of the year.

[145] In its Reply Submissions, PHP expressed concern that requiring advance approval of the operating procedures could delay its ability to take service under the ELID Tariff effective January 1, 2027. However, it agreed that an after-the-fact review of the procedures could be undertaken and it supported a full and transparent review of the calculation of the Dispatchable Rider credit, either through a FAM audit or annual review process for the ELID Tariff.

[146] In its rebuttal evidence, NS Power resisted the suggestion that the Board should approve the operating procedures, questioning whether this would provide improved regulatory oversight.

2.6.2.1 Findings

[147] Because of their importance in determining the Dispatchable Rider credit, the Board directs NS Power to file its operating procedures with the Board for approval when developed. The Board does not agree with Mr. Bowman that the operating procedures should reflect practical control of dispatch by NS Power because of the fundamental voluntary nature of the mechanism. The filing of the operating procedures for approval does not need to occur before the ELID Tariff is implemented but should occur as soon as possible.

2.6.3 Should the Dispatchable Rider be Optional?

[148] In its Closing Submissions, PHP raised, for the first time in this proceeding, the suggestion that the Dispatchable Rider should be optional under the ELID Tariff. It said it is "concerned about the costs and risks of continuing to offer the dispatchability service" and, "[i]n light of the various issues raised and positions advocated by the parties to the hearing", urged the Board to make it clear that the Dispatchable Rider was intended to be optional.

[149] The Industrial Group considered this to be a substantive redesign of the tariff, not a clarification. It argued that this proposal was not costed and that a tariff designed around dispatchability cannot be assumed appropriate without it.

[150] Likewise, NS Power expressed concern about PHP's "new and untested proposal...that would fundamentally change the overall tariff structure". NS Power argued that the Dispatchable Rider was foundational to the development of the ELID Tariff and noted there was already a degree of optionality in the tariff itself, since PHP has the discretion to follow dispatch instructions. NS Power also argued that allowing the Dispatchable Rider to be optional would introduce unpredictability around its resources for dispatch planning from year to year.

2.6.3.1 Findings

[151] The Board finds that the Dispatchable Rider should not be optional. It is a fundamental aspect of the proposed ELID Tariff. PHP's request that it be confirmed as optional is a fundamental change to what NS Power proposed in its application. Its impact on the proposed tariff structure has not been able to be considered or tested since it was not raised by PHP until its Closing Submissions.

2.6.4 Reporting

[152] NS Power proposed annual reporting to the Board to confirm the value of system savings achieved through the dispatch of PHP's load. It said it would endeavour to file this report no later than 60 days after the end of a tariff year.

[153] Mr. Bowman said the Board should require NS Power to provide at least quarterly reporting that includes estimates of the Dispatchable Rider value for the full year, based on year-to-date results. In its Closing Submissions, the Industrial Group added that quarterly reporting should also include disclosure of the specific adjustments made to the underlying cost simulation sufficient to allow the Board and interested parties to verify that the credit paid to PHP is demonstrably tied to PHP's decision to shift load in response to system conditions and energy prices (including any randomization of maintenance outages and any other subjective adjustments).

[154] In its rebuttal evidence, NS Power noted the Dispatchable Rider credit calculation was an annual exercise that relied on PHP's actual annual load, the system annual profile, and fuel market prices throughout the year. It said more frequent reporting is likely to be misleading and subject to significant adjustment. It submitted no additional reporting should be required.

[155] PHP supported a review of the calculation of the Dispatchable Rider credit as part of the FAM audit. It said it was also not opposed to the continued tracking of cause code information outlining reasons for varying from dispatch directions, although it does not believe that this is relevant to the calculation of the credit. In particular, it emphasized that "[a] *post facto* subjective review of the intention of PHP behind its load shifting in every hour of the year is neither necessary nor appropriate and would simply

disincentivize PHP from load-shifting if the value of its compliance was subject to potential subsequent disallowance".

2.6.4.1 Findings

[156] The Board agrees with NS Power that, given the way that the Dispatchable Rider credit is calculated, quarterly reporting is of limited value because the results could be quite variable over the course of the year, affecting their use to assess trends or identify issues or concerns. The Board finds that annual reporting is more appropriate and directs NS Power to provide a report on the operation of the Dispatchable Rider no later than March 1st each year.

[157] The Board also finds that the content of the report should include the following:

a. actual system cost for the year and details about how this amount was calculated;
b. the methodology and all assumptions used to determine the counterfactual customer baseline load for PHP;
c. the system cost for the year under the counterfactual customer baseline load for PHP and details about how this amount was calculated; and
d. cause code information outlining reasons for varying from dispatch directions.

2.7 Revenue-to-Cost Ratio

[158] In developing the ELID above-the-line tariff for PHP and determining appropriate costing, NS Power's analysis resulted in a revenue-to-cost ratio of 1.0438 for 2026 and 1.0471 for 2027. However, PHP and its consultant do not agree with a revenue-to-cost ratio greater than 1.0 for a new above-the-line tariff. Brubaker stated:

> Under the Company's proposed ELID rate design, the Revenue-to-Cost ("R/C") ratio would be 1.04373 and results in an over-recovery of 4.373% above the cost to serve PHP. While an R/C ratio exceeding 1.0 can be a valid tool to mitigate the impact of shifting Cost-of-

> Service (“COS”) models on other classes, that justification does not apply here. PHP is in a new above-the-line customer class and has not previously benefited from below or above cost rates or model changes in the Cost-of-Service Study (“COSS”) that disadvantaged other classes. Therefore, we recommend an equitable R/C ratio of 1.0, ensuring PHP pays exactly its cost to serve without subsidizing or being subsidized by other classes.
>
> [Exhibit N-2, p. 3]

[159] Brubaker suggested that applying a revenue-to-cost ratio greater than 1.0 to a customer transitioning from a marginal cost-based rate to an above-the-line tariff is generally considered inappropriate because it violates the fundamental regulatory principle of cost causality.

[160] The Small Business Advocate noted that NS Power’s proposed revenue-to-cost ratio for PHP is reasonable and appropriate. In its Closing Submissions, the Small Business Advocate stated:

> …Any new customer of NS Power is subject to the R/C ratios of the class or tariff they are joining. While a new customer may not have benefited from a previous adjustment to the R/C ratio for the tariff that they are taking power under, this fact does not alter the R/C ratios to which they would be subject when they join the new class or take service under a new tariff. The SBA respectfully submits that it is reasonable and equitable that PHP be treated like all new customers and submits that PHP should pay the rate of the tariff it joins as a new customer, whether it be the ELID Tariff or another tariff.
>
> NS Power confirmed in its response to SBA IR- 8, that the ratio of 1.04373 aligns with other ATL customers in the 2026/2027 GRA such as the "General, Large General, Small Industrial, Medium Industrial, Large Industrial and Municipal class". The SBA therefore further submits that applying the R/C ratio to PHP as proposed in the ELID Application is reasonable and is aligned with the treatment of other classes and other new customers.
>
> [Small Business Advocate, Closing Submissions, p. 10]

[161] The Consumer Advocate’s consultant, InterGroup, stated:

> In response to an information request from the Consumer Advocate, NSP stated “the alignment of PHP’s revenue-to-cost (R/C) ratio with other classes (initially at 1.05; subsequently revised to 1.0438 for 2026 and 1.0471 for 2027) as a foundation for the ELID Tariff costing was understood by Parties to the SA and reflected in the subsequent Cost of Service information circulated among Parties and included in the General Rate Application.
>
> [Exhibit N-19, pp. 5-6]

[162] The Consumer Advocate also addressed the revenue-to-cost ratio issue:

> With respect to PHP’s proposal regarding setting PHP’s R/C ratio at 1.0, the CA respectfully submits that the use of a 1.04 R/C ratio was understood by all parties, and also

> falls within the Board's standard zone of reasonableness of 0.95 to 1.05. Indeed, as noted by the Chair during questioning of the BAI panel, one of the reasons regulators use a range is that cost of service studies are not exact. There are assumptions and estimates involved in them and the range recognizes that there is imprecision in the measurement. BAI also provided no clear recommendation on how to redistribute the resulting revenue shortfall. But to be clear – the only options available involve either raising rates to other ATL customers, whether in the current GRA period or deferred to some future period, or for NSPI not to collect its full revenue requirement and therefore not have the opportunity to earn their approved return on equity. Those are the only possible outcomes, neither of which are consistent with the SA. [Footnotes omitted]
>
> [Consumer Advocate, Closing Submission, p. 15]

[163] In its Closing Submissions, referring to the revenue-to-cost ratio of 1.04, PHP noted that it would face a significant increase in its contribution to fixed costs, compounded by the proposed premium on its overall rate. It also mentioned that, at the hearing, its consultant was asked whether it is appropriate to change the revenue-to-cost ratio for one class of customer just because it is a new rate. In response, Michael Gorman from Brubaker stated:

> **A.** (Gorman) Well, I think this rate provides some flexibility on that with the deferral account. So since NS Power can be made whole for any small changes that we're proposing here, the deferral account could pick up those differences in revenue, then the Board can decide how it will go about recovering that deferred cost.
>
> [Transcript, September 22, 2026, pp. 304-305]

[164] The Industrial Group took issue with the deferral account comments:

> The availability of the Deferral Account also does not justify PHP's requested revenue-to-cost ("**R/C**") reduction. PHP quotes Mr. Gorman's evidence that "NS Power can be made whole" through deferred recovery and describes the resulting impact on other classes as "minimal". However, making NSPI whole does not protect other customers from the transferred cost. Deferral postpones recovery; it neither eliminates the amount to be recovered nor establishes that other customers should bear it.
>
> As the CA explains, the alternatives are "raising rates to other ATL customers, whether in the current GRA period or deferred to some future period," or NSPI not collecting its full revenue requirement. PHP may seek a different rate, but the Deferral Account is not a ratemaking justification for granting it. The requested R/C reduction must stand on its merits, with the consequences for other classes identified. [Footnotes omitted]
>
> [Industrial Group, Reply Submissions, p. 8]

[165] In addressing the revenue-to-cost ratio issue, NS Power stated:

> There is an acceptable range in R/C ratios that is well documented within the regulatory sector. For this reason, this jurisdiction has adopted a 'band' of 0.95-1.05 that sets out the justifiable variance in R/C ratios. PHP's R/C ratio of 1.04 is within this band. Nothing brought forward at the hearing suggests that there is an existing precedent or principle that a new ATL class should start at a neutral position of 1.0%. Rather, this appears to be an argument that PHP is bringing forward without any additional backing, despite their previous Agreement to a ratio of 1.04%. Mr. Fitzhenry conceded at the Hearing that he is not aware of any regulator that requires class R/C ratios of 1.0 and that a new customer taking service under an existing rate will pay the R/C ratio for that class, even without any history in that class…
>
> All told, there has been no evidence presented that the R/C ratio applied to PHP is improper, lacks precedent, or should be altered.
>
> [NS Power, Closing Submissions, pp. 15-16]

2.7.1 Findings

[166] Although it may be desirable to strive towards revenue-to-cost ratios of 1.0 for all customer classes, assumptions and estimates in cost-of-service studies result in imprecision. Recognizing that cost-of-service studies are not exact, it has long been acceptable to consider revenue-to-cost ratios within a band of 0.95 to 1.05 as reasonable in minimizing potential cross-subsidization. In this current matter, the revenue-to-cost ratios of 1.0438 for 2026 and 1.0471 for 2027 are within the 0.95 to 1.05 range and are therefore considered by the Board to be reasonable. Additionally, since this revenue-to-cost ratio was assumed in NS Power's COSS in its 2026-2027 GRA, the Board finds, given it is in the Board's accepted reasonable range in any event, it should be maintained, rather than shifted in isolation of the resulting impacts on other rate classes.

2.8 Energy and Regulatory Boards Act Factors

[167] When assessing whether to approve a tariff, the Board must consider certain factors under the *Energy and Regulatory Boards Act*. Section 6(2) states:

> **6 (2)** In approving or fixing rates, tolls, charges, tariffs, … the Board shall give appropriate consideration to the extent to which such rates, tolls, charges, tariffs, …
>
> (a) support competition and innovation in the provision of energy resources in the Province;

> (b) support the development of a competitive electricity market;
>
> (c) ensure the provision of safe, secure, reliable and economical energy supply in the Province;
>
> (d) support sustainable development and sustainable prosperity; and
>
> (e) support such other factors as prescribed by the regulations, with the goal of approving rates, tolls, charges, tariffs, capital applications or other matters that are consistent with the purpose of this Act, the *More Access to Energy Act* and the regulations.

[168] Section 2 of the *More Access to Energy Act*, SNS 2024, c 2, Sch B, *s*ets out its purpose, and includes similar, although not identical, objectives to the list of factors:

> (a) increase competition and innovation in the Province's energy sector;
>
> (b) ensure the provision of a safe, secure, reliable and economical energy supply in the Province;
>
> (c) ensure a transparent, efficient and coordinated approach to Provincial energy-supply planning;
>
> (d) provide for competitive procurement practices for new energy-system resources;
>
> (e) support the sustainable development, sustainable prosperity, energy efficiency and greenhouse gas emissions reduction goals of the Province articulated in the *Environmental Goals and Climate Change Reduction Act*; and
>
> (f) provide for a phased transition of the system operator from Nova Scotia Power Incorporated to an Independent Energy System Operator.

[169] PHP and NS Power made similar submissions, addressing the innovative nature of the Dispatchable Rider that allows for significant control of PHP's large industrial load and the system wide benefits this can provide. These parties say that the tariff also promotes reliable, economical and efficient use of energy in Nova Scotia and supports competition by allowing for the integration of more wind in Nova Scotia.

2.8.1 Findings

[170] Not all the factors listed in the *Energy and Regulatory Boards Act* and the *More Access to Energy Act* are applicable to every application. That is why the legislation says the Board must give “appropriate regard” to these factors. The ELID Tariff does touch on a few of the listed factors. PHP has been on a below-the-line rate for several years. Moving PHP to a more typical above-the-line rate should, in theory, have beneficial impacts on rates because the ELID Tariff is designed to recover the full embedded costs of serving PHP’s load. The ELIADC Tariff was not. There is also a unique feature of the ELID Tariff which carries over from the ELIADC. That is the dispatchability service which provides NS Power with a degree of control over PHP’s load for operational planning purposes. This means that on a daily basis, NS Power can work with PHP to determine the level of load that will produce the optimal generation resource mix. Because of the intermittent nature of wind generation, this can allow a more efficient use of this energy source. The interruptible component of the tariff not only gives NS Power even more control over the PHP load in emergency situations but also produces long-term capital costs savings. This therefore touches on both reliability and more economic power production. The load flexibility provided by the Dispatchable Rider does assist in the integration of existing Independent Power Producer energy from wind and solar and should do so for the future planned wind farms. Renewable energy is a key component in the Province’s plan to control greenhouse gas emissions. Therefore, based on the foregoing, the Board agrees with NS Power and PHP that the proposed ELID Tariff is aligned with the relevant objectives of the *Energy and Regulatory Boards Act* and the *More Access to Energy Act.*

3.0 SUMMARY OF BOARD FINDINGS

[171] The Board approves the proposed ELID Tariff, effective January 1, 2027, subject to the changes discussed in this decision. These changes include:

- the ELID Interruptible Rider credit will be $13.107 per kVA;
- the Dispatchable Rider credit will be shared, with 90% of savings being paid as a credit to PHP and 10% retained for the benefit of FAM customers (including PHP under the ELID Tariff); and
- the Operating Procedures for the Dispatchable Rider must be approved by the Board (the filing for approval should be as soon as possible but may occur after the implementation of the ELID Tariff).

[172] NS Power is directed to revise the proposed tariff language in a compliance filing, to be consistent with the Board's findings in this decision, no later than December 1, 2026.

[173] Additionally, NS Power is further directed as follows:

- Track all costs for the administration of the tariff covered by the Customer Charge so that the information is available to set the charge in NS Power's next GRA;
- to engage with interested parties to further review its cost-of-service methodology to consider an alternative to its existing 3CP approach to appropriately allocate demand-related costs to PHP and other potential large, highly interruptible loads, which may appear in the future, and the other cost-of-service elements NS Power was directed to review in its 2026-2027 GRA;
- the results of the cost-of-service review must be brought forward to the Board for approval early enough that it can be approved before NS Power's next GRA; and

- to file annual reports with the Board about the operation of the ELID Tariff, no later than March 1st each year, including:
    - actual system cost for the year and details about how this amount was calculated;
    - the methodology and all assumptions used to determine the counterfactual customer baseline load for PHP;
    - the system cost for the year under the counterfactual customer baseline load for PHP and details about how this amount was calculated; and
    - cause code information outlining reasons for varying from dispatch directions.

[174] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 24th day of November 2026.

Stephen T. McGrath

Richard J. Melanson