

NOVA SCOTIA ENERGY BOARD

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

-and-

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

BATES WHITE INFORMATION REQUESTS RESPONSES
Public Redacted

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Responses Due: **Thursday, June 18, 2026**

Copies: 1 electronic copy (PDF searchable)

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Issued at Halifax, Nova Scotia, this 18th day of June 2026.

1 **Request IR-1:**

2 **Reference: N-20, Bates White Evidence, pp.10-13.**

3 [O]ur evidence addresses only the Customer Charge, Energy Charge, Dispatchable
4 Rider, and treatment of Goose Harbour output.

5 Does Bates White's decision not to address the Interruptible Demand Credit or the Priority
6 Interruptible Credit reflect a limitation in the mandate assigned by Board counsel or a
7 deliberate decision not to opine on those components?

8 **Response IR-1:**

9 Our decision to not address the Interruptible Demand Credit or the Priority Interruptible Credit
10 reflects a limitation in the mandate assigned by the Board.

1 **Request IR-2:**

2 **Reference:** N-20, Bates White Evidence, pp.10-13.

3 **Preamble:** Throughout this section, Bates White assesses the Customer Charge
4 **Methodology and the Risk of Under-Recovery.** At p. 12, lines 10-22, the evidence states:

5 *NSPI did not use a bottom-up methodology (using assumed labour hours*
6 *and labour rates) to develop the estimate, nor did it use historical data to*
7 *develop its estimates despite operational process similarities between the*
8 *ELID and ELIADC Tariffs.*

9 And, at p. 12 line 24, and p. 13, lines 1-2:

10 *We do not agree that NSPI has made the “conservative” choice. Rather, NSPI*
11 *has selected the value from its range that is most likely to under-collect the*
12 *costs that the Customer Charge is intended to recover.*

13 (a) Does Bates White agree that, without either a bottom-up methodology or
14 historical ELIADC cost data to estimate the Customer Charge, the resulting
15 estimated low, mid, and high ranges of NSPI's projection cannot be
16 considered well-supported, regardless of which point in the range is
17 selected? Please explain why.

18 (b) Where NSPI has selected the value "most likely to under-collect" the costs
19 the Customer Charge is intended to recover, and that tracking challenges
20 will limit the ability to capture under-recoveries via the PHP Deferral
21 account, does Bates White agree that, in practice, any under-recovery will
22 be borne by other ATL customers rather than PHP? Why or why not?

23 (c) Is Bates White's recommended midpoint of \$12,291.67/month made on the
24 basis that the midpoint is the most accurate estimate, or is it a practical
25 compromise in the absence of a proper methodology? Please explain why
26 this approach would yield the most just and reasonable rate.

27 (d) Where Bates White recommends that if actual administration costs fall
28 *below* Customer Charge collections, PHP should receive 100% of the
29 excess as credits, does Bates White also recommend that the converse
30 should apply i.e., that costs *above* collections should be recovered 100%
31 from PHP?

(e) Does Bates White have a recommendation regarding tracking and reporting to make either direction of adjustment verifiable?

Response IR-2:

(a) The Customer Charge cost estimate range put forth by NSPI has limited support. As we explain in our evidence, “NSPI’s methodology for developing the [Customer Charge] estimate is not well explained in its Application, and what is explained is not compelling.” As such, we recommended NSPI file additional evidentiary support for its proposed Customer Charge.

(b) Please see the response to BW-SBA-1 (b).

(c) Our recommendation is that NSPI file additional evidentiary support for its proposed Customer Charge. Such supporting evidence would allow for a better review of the appropriateness of the proposed Customer Charge. Only in the event that no such supporting evidence is filed do we recommend an alternative approach. That alternative approach is to increase the Customer Charge (to \$12,291.67/month) and to subject those costs and that cost recovery to a thoroughly-explained reconciliation mechanism that ensure 100% of the costs incurred for administering the ELID Tariff be recovered from PHP.

(d) Yes.

(e) We have not included an explicit tracking mechanism in our evidence. However, such a mechanism may include hourly labor cost tracking where time spent on ELID Tariff administration is explicitly tracked and reported to allow for verification and review. We would expect PHP to be interested in this data as well to ensure it is paying the administration costs of its Tariff, and not those of other parties.

Request IR-3:

Reference: N-20, Bates White Evidence, p. 15, lines 5-8:

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 ... thus approximately 29% greater than represented in the COSS.

And at p. 16, lines 10-13 and 15-16:

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...

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.

(a) Please confirm that Bates White has calculated that reduction in revenue using the full 168 MW Goose Harbour capacity and a revised PHP gross load. If so, is the COSS-modelled net PHP load approximately 2.5 times too high, producing an Energy Charge rate that is materially too low? Please elaborate.

(b) If the rates are approved without correction, please confirm that other FAM customers will fund the resulting shortfall, estimated at approximately \$21 million annually in 2027? If not, what is the anticipated source of this shortfall?

(c) Has Bates White calculated (or is it able to calculate) the revised Energy Charge with these two adjustments? Please provide.

Response IR-3:

(a) Yes, we conclude that PHP net load incorporated in the COSS model is too low, and that it produces an Energy Charge that is materially too low.

(b) Confirmed.

(c) Bates White had insufficient information to fully calculate a revised Energy Charge with the two adjustments, because a number of key values in the associated Excel workbook are hardcoded, but would change based on the two adjustments.

1 Request IR-4:

2 Reference: N-20, Bates White Evidence, pp. 16-17:

3 *Another issue that is notable, but likely of less significance than proper*
4 *representation of the Goose Harbour facility capacity, is the fact that the*
5 *generation of the facility assumed in the COSS is at the P90 level, meaning*
6 *the annual output from the facility that is expected to be exceeded 90% of*
7 *the time. Considering the potential distortions described above from actual*
8 *Goose Harbour output exceeding the modeled level used to set the Energy*
9 *Charge, it would be more appropriate to use a P50 output level in the COSS,*
10 *such that there is equal probability that actual generation is higher or lower*
11 *than that used to set rates. While we think the P50 level is more appropriate*
12 *in principle with respect to setting the ELID Energy Charge, we do not believe*
13 *moving to a P50 level (at the 168 MW capacity level) would be justified in*
14 *advance of actual operational performance at the Goose Harbour facility. The*
15 *reason for this position is that the P90 level reflected in the COSS (at the*
16 *130.5 MW capacity level) corresponds to a capacity factor of 44%, which is*
17 *relatively high, even in the context of Nova Scotia's high wind potential.*

18 And Reference: N-4, NSPI (BW) RIR-4 (a-c), lines 20-23:

19 *NS Power cannot comment on the amount of generation required to meet*
20 *PHP's energy demand as PHP's load forecasting is a PHP internal process.*
21 *This is similar for PHP's wind forecast in which PHP provided NS Power with*
22 *its P90 forecast to utilize in NS Power's F&PP forecasts.*

- 23 (a) Why does Bates White believe this issue is of less significance?
- 24 (b) What is the rate and cost impact of using P90, rather than P50 (holding all
25 other COSS inputs constant), from the perspective of PHP and other
26 ratepayers? Please provide any analysis.
- 27 (c) What is the risk to other ratepayers of setting the output level too
28 conservatively?
- 29 (d) Please provide the calculation underlying the 44% capacity factor figure,
30 including the specific annual generation output (in GWh) and installed
31 capacity (in MW) used to derive it.
- 32 (e) Given that the P90 level reportedly yields a 44% capacity factor, which
33 appears to be a concern to Bates White, can Bates White confirm that the
34 P90 in this case in fact refers to a conservative forecast rather than an
35 optimistic forecast? Please outline Bates White's source in reaching this
36 conclusion.

- 1 (f) What annual capacity factor does Bates White believe is more reasonable
2 than the noted 44% annual capacity factor? Please provide the studies or
3 comparables relied upon in answering.
- 4 (g) In principle, is it appropriate to use a P90 or P50 in preparing this cost-of-
5 service study? Please specifically address whether it is more appropriate
6 to use a conservative estimate or a likely estimate in setting a rate.
- 7 (h) Please confirm the record does not currently have a P50 estimate? If not,
8 please indicate where this can be found for both 168 MW and 130.5 MW
9 capacity levels.
- 10 (i) What specific threshold or quantum of operational data would Bates White
11 require before it would recommend moving from a P90 generation level for
12 purposes of setting the ELID Energy Charge? For example, would one year
13 of operational data suffice?
- 14 (j) How and through what regulatory mechanism does Bates White envision
15 the generation assumption being updated?

16 **Response IR-4:**

- 17 (a) We do not believe the use of a P90 value has great significance in part because the
18 assumed capacity factor of 44% is already fairly high, and consistent with historical
19 performance of relatively new and large wind farms in Nova Scotia. In our professional
20 experience, the difference between P90 and P50 estimates of wind farm of the scale of
21 Goose Harbour are not large in the context of the other factors discussed in the
22 evidence.
- 23 (b) The P50 level of output for the Goose Harbour facility is not in evidence. It will be a
24 larger output than the P90 level assumed in the COSS, and all else equal, it would result
25 in a lower PHP net load. If the lower PHP net load were incorporated in the COSS
26 model, all else equal, it would result in a higher ELID Energy Charge rate. If PHP net
27 load is in reality lower than used to set the Energy Charge rate, a lower amount of
28 system fixed costs would be recovered from PHP, and a larger amount of system fixed
29 costs would be borne by FAM customers.
- 30 (c) See response to IR-4(b)

- 1 (d) The 44% capacity factor was calculated from values in the Goose Harbour PPA: facility
2 Nameplate Capacity of 130.5MW, and Energy Bid (i.e., facility output) of 507,400
3 MWh/year. The calculation is the ratio of expected output to the output if the facility
4 operated at full capacity for all 8760 hours in the year: Capacity factor =
5 $507,400 / (130.5 \times 8760) = 0.444$.
- 6 (e) P90 is defined as the level of output that is expected to be exceeded 90 percent of the
7 time (typically on an annual basis). Hence, it is a relatively low number. P50 is the level
8 of output that is expected to be exceeded 50% of the time. Hence, it is higher than the
9 P90 value, and would produce a capacity factor greater than 44%.
- 10 (f) Bates White did not estimate a capacity factor for the Goose Harbour facility at P50
11 output.
- 12 (g) There is no general principle that applying a P90 or P50 output value is more
13 appropriate in a given cost of service study. With respect to particular circumstances of
14 the proposed ELID, applying a lower output estimate for Goose Harbour exacerbates the
15 problems that stem from calculating PHP load net of output from Goose Harbour.
- 16 (h) Confirmed.
- 17 (i) Our concerns regarding the ELID, the determination of PHP net load, and the
18 determination of the ELID Energy Charge would not be resolved by using a P50 rather
19 than P90 value for Goose Harbour output in the COSS. As quoted in the question, we
20 consider the issue to be “likely of less significance” than the assumed installed capacity
21 of the Goose Harbour facility. One year of actual output data would not allow for a
22 reliable determination of a P50 value.
- 23 (j) As discussed in the Bates White evidence, we recommend “that NSPI be required to
24 update the COSS model to better reflect likely PHP net load, capturing both updates to
25 expected PHP gross load and, most importantly, the likely output from Goose Harbour at
26 a facility capacity of 168 MW” (page 35, lines 11-14); and “[i]n addition to correcting the
27 Energy Charge rates, we recommend that a true-up mechanism be created to address
28 substantial deviations of PHP net load from expectations....” (page 35, lines 23-24)

Request IR-5:

Reference: N-20, Bates White Evidence, at p. 21, lines 2-6 notes a second concern:

Our second concern is that the DR credit is built upon a shaky premise, namely, that PHP's load is sufficiently predictable as to allow for an after-the-fact determination of how PHP would have operated over an entire year. PHP's load can be volatile and unpredictable, as is demonstrated by recent historical data. [emphasis in original]

And Reference: N-20, Bates White Evidence, at p. 22, lines 6-10:

PHP's forecast error has averaged [REDACTED] per year and has reached as high as [REDACTED] (in 2023). This forecast error has averaged [REDACTED] GWh/year and peaked at [REDACTED] GWh (also in 2023).

And Reference: N-20, Bates White Evidence, at p. 24, lines 7-12, notes its third concern:

Further, other factors, such as PHP's book of business, equipment performance (e.g., partial outages) and efficiency (e.g., degradation), macroeconomic factors (e.g., tariffs), taxes, labour availability, and any other potential variable that impacts PHP's operational profile will be difficult or impossible to fully capture. Importantly, many of these variables are unrelated to the price of energy in Nova Scotia, meaning PHP's load may be moving around for reasons other than PHP seeking to lower system-wide FAM costs in the province.

(a) Does Bates White agree that NSPI, as an external party without access to PHP's order book, equipment status, or operational plans, faces at least as great a challenge in constructing a credible CBL as PHP faces in forecasting its own load? If not, please explain.

(b) At p. 21, Bates White calculates that the spread between PHP's high and low actual load years since 2020 is approximately [REDACTED] GWh, which at \$100/MWh, is approximately \$[REDACTED] million in potential FAM cost variability. Who bears the cost risk of percentage error in the CBL?

(c) Bates White identifies that many variables affecting PHP's load are "unrelated to the price of energy in Nova Scotia." Is there a CBL methodology that can reliably separate the price-responsive component of PHP's load variation from the component driven by these external factors? Please explain.

1 (d) Is this any different than how demand response was operationalized and
2 costed under ELIADC? Please explain and if not different, why this would
3 be of concern (or more concern) now.
4

5 **Response IR-5:**

6 (a) Yes.

7 (b) FAM customers.

8 (c) There may be, but we have not developed one. Our recommendation is that any
9 payments to PHP from FAM customers under the DR credit must be demonstrably tied
10 to PHP deciding to shift load due to energy prices and that FAM customers not be at risk
11 of providing any compensation to PHP in hours where no load-shifting activity due to
12 energy prices occurred.

13 (d) The proposed ELID Tariff's use of an *ex post* calculation to identify demand control
14 benefits has similarities with the ELIADC Tariff's use of a similar mechanism to
15 determine load-shifting benefits after the fact. The proposed ELID Tariff differs from the
16 ELIADC Tariff in key ways, most notably use of an embedded cost rate and the
17 consideration of the Goose Harbour Wind Farm output. Bates White has noted concerns
18 about changes in fuel costs caused by exogenous or random events masking the actual
19 demand control benefits achieved by the ELIADC Tariff. See, for example, Conclusion
20 XV-6 in Bates White's 2022-2023 FAM Audit Report.

1 **Request IR-6:**

2 **Reference:** N-20 [Bates White Evidence](#), at p. 23, lines 19-23.

3 *We are unconvinced that PHP would ever have incentive to levelize its load.*
4 *PHP itself explains that its load is dependent on its business activity, is*
5 *subject to seasonal fluctuations, and can spike up to consume as high as*
6 *25% of the power in Nova Scotia at any given time. It is unrealistic to expect*
7 *levelized load at PHP when its energy consumption is “closely tied to the*
8 *order book for paper” and which is generally higher demand in winter and*
9 *summer months (and lower demand in spring and fall months).*

10 **And Reference:** N-11, PHP (BW) RIR -2.

11 *The market for paper is somewhat seasonal with winter and summer months*
12 *having generally less demand than spring and fall.*

13 (a) Does Bates White agree that its finding that PHP would have higher
14 demand in winter and summer months is inconsistent with PHP's evidence
15 on this proceeding? If not, please explain.

16 (b) If confirmed, are there any consequential revisions to Bates White's
17 evidence?

18 (c) Does a levelized high load factor CBL overstate the savings attributable to
19 PHP's load pattern regardless of how accurately the CBL mechanics are
20 implemented? Please explain.

21
22 **Response IR-6:**

23 (a) Yes. PHP's response to BW-IR-2 states: "The market for paper is somewhat seasonal
24 with winter and summer months having generally **less** demand than spring and fall.
25 PHP's energy demand corresponds to this seasonal variance." (emphasis added)

26 (b) No. Our point in the referenced section is that PHP's inherent business seasonality
27 translates into energy demand seasonality that is not consistent with NSPI's assertion
28 that PHP would consume energy on a levelized basis. The timing of specific "high" and
29 "low" seasons is irrelevant.

30 (c) We have not conducted such an analysis. Our concern with this portion of the DR Credit
31 is that the calculation of the DR Credit will be inaccurate as it will be based on a faulty
32 premise (i.e., that PHP would consume energy on a levelized basis).

1 **Request IR-7:**

2 **Reference:** N-20, Bates White Evidence, at p. 24, lines 12-13, third concern with the DR
3 **credit:**

4 *In such instances, it would be inappropriate for FAM customers to pay PHP*
5 *for changes to its load profile that would have been made regardless of the*
6 *ELID Tariff and its components.*

7 (a) Is Bates White saying that the ELID, or the DR credit specifically, should
8 not pay PHP for load variations that are done for reasons other than
9 responding to NSPI's pricing signals?

10 (i) If not, what does Bates White mean it would be
11 inappropriate for FAM customers to pay for these changes
12 in load profile?

13 (b) If so, how does Bates White propose the ELID Tariff be modified to track
14 the reasoning for load variations that fall outside of NSPI's price signalling
15 or requests?

16 (c) Under the ELIADC structure, have FAM customers been similarly
17 inappropriately paying PHP for its changes in load profiles it would have
18 made regardless of that tariff? Please explain why or why not, as compared
19 to the currently proposed structure of the ELID.

20
21 **Response IR-7:**

22 (a) Yes.

23 (i) Not applicable.

24 (b) We have not put forth an alternative tariff mechanism. As we state in our evidence, we
25 do not recommend that the Board approve the DR credit as proposed. We do explain
26 that the DR credit must achieve two objectives to be reasonable, in our view. First, any
27 payments to PHP from FAM customers under the DR credit must be demonstrably tied
28 to PHP deciding to shift load due to energy prices. Second, FAM customers must not be
29 at risk of providing any compensation to PHP in hours where no load-shifting activity due
30 to energy prices occurred. As we state in our evidence, it may be that, with additional

1 elaboration, revisions, reporting requirements, and verifiability guardrails, the
2 mechanism may achieve these objectives, but as proposed, it is our view that the DR
3 credit is too vague, uncertain, unverifiable, and at risk of failing to match rider payments
4 to load-shifting service to be recommendable for approval.

5 (c) The ELIADC Tariff's structure differs from the proposed ELID Tariff in that PHP pays for
6 energy at a variable rate that changes with market conditions, whereas under the ELID
7 Tariff, PHP would pay an energy rate that is fixed and does not vary with market
8 conditions. In our view, the ELIADC Tariff has provided load shifting benefits, but that
9 those benefits can be obscured by exogenous and random events that impact overall
10 fuel and purchased power costs. Please also see our response to BW-IG-5 (d).

Request IR-8:

Reference: N-20, Bates White Evidence, fourth concern, p.26, lines 3-11.

According to NSPI, assuming that “for that [2025] period, if PHP load had been dispatched at 100 percent optimal,” the DR credit would have been “approximately \$7 to \$11 million.” However, NSPI explains that “[i]n reality” the calculated DR credit would have been “half that amount,” or \$3.5 to \$5.5 million. This means NSPI’s discretionary adjustments would reduce the DR credit by \$3.5 to \$5.5 million. The adjustments NSPI made in its analysis included “system conditions, customer production constraints/requirements, etc.,” which are subjective, vague, difficult to verify, or some combination of the three. NSPI could not provide the specifics of the adjustments made “due to the cyber incident,” which rendered the analysis “no longer available.”

(a) Is it Bates White’s opinion that there is currently no basis either in the evidence or in the proposed Operating Procedures upon which the Board or Intervenor could assess whether NSPI’s annual discretionary adjustments to the DR credit are appropriate? Please explain.

(b) Is the \$3.5 - \$5.5 million gap between the "optimized" DR credit (\$7–11 million) and the "realistic" DR credit (\$3.5–5.5 million), the measure of NSPI’s discretion? If not, what does it represent?

(c) What verification mechanism does Bates White consider necessary to allow the Board and intervenors to assess NSPI’s discretionary adjustments after-the-fact? Please specify what data NSPI must produce, in what form, and by what process a dispute about the appropriateness of an adjustment would be resolved.

Response IR-8:

(a) Yes, to the extent the question’s reference to “Operating Procedures” is referring to IG-NSPI-IR-12 Attachment 1.

(b) Yes.

(c) We have not proposed such a mechanism, nor is it our conclusion that a verification mechanism would sufficiently address the concerns we have with the proposed DR Credit. However, to be responsive to the request, any such mechanism should allow full

- 1 discovery from NSPI regarding its model inputs, assumptions, outputs, and adjustments
- 2 made to the results and allow for stakeholder testimony, with the onus demonstrating the
- 3 reasonableness of the DR Credit calculation residing with NSPI.

Request IR-9:

Reference: N-20, Bates White Evidence, p.26, line 18- p. 27, line 2 describes its fifth concern relating to the use of forward replacement fuel pricing:

However, NSPI has specifically veered away from using forward replacement costs to conduct hypothetical system cost calculations in recent years, including in determining load-shifting benefits provided by PHP under the ELIADC Tariff due to concerns that use of forward replacement fuel pricing “overstates the cost of the actual fuel consumed.” It is unclear why NSPI has proposed to use forward replacement pricing when calculating the DR credit for PHP despite its prior concerns.

(a) Is it Bates White’s understanding that NSPI is using the same forward replacement fuel costs methodology which it argued was unreliable in 2022 due to significant volatility in commodity prices? If not, please explain the difference.

(b) What is Bates White’s understanding of NSPI’s rationale to use this methodology in the proposed ELID tariff to calculate the credit?

(c) Is Bates White’s objection to using forward replacement fuel costs in the ELID CBL simulation that it would inflate the hypothetical CBL system costs, and therefore inflate the DR credit payable to PHP, at the expense of other ATL customers? Please explain.

(d) Does Bates White recommend that NSPI use actual fuel costs (or an alternative), as a prerequisite to approval of the DR credit mechanism? Please explain.

Response IR-9:

(a) NSPI’s responses to NSPI-Synapse IR-24 (d) and NSPI-IG IR-16 (d) do not sufficiently elaborate on the specifics of the use of “forward replacement costs” to determine if the methodology being proposed is identical to the methodology abandoned in 2022. Still, use of forward replacement pricing was found by NSPI to overstate the cost of actual fuel consumed—see, for example, NSPI’s March 1, 2023 filing in matter M11021, “Re: Extra Large Industrial Active Demand Control (ELIADC) Tariff – 2022 Annual Report,” pages 2 to 3.

1 (b) We did not observe any rationale provided by NSPI in its Application or the referenced
2 IR responses.

3 (c) Our concern with this approach is that it appears to vary from NSPI's recent approach in
4 administering the ELIADC Tariff due to NSPI's concerns that forward replacement
5 pricing overstates fuel costs and NSPI has not addressed the apparent inconsistency.

6 (d) To address our specific concern, NSPI should clarify the specifics of the methodology
7 and adequately address the inconsistency identified in response to part (c).

1 Request IR-10:

2 Reference: N-20, Bates White Evidence, p. 27, lines 4-9.

3 *Our sixth concern is that the DR credit represents a zero-sum mechanism*
4 *that, if incorrectly calculated, could harm other FAM customers. Any load*
5 *“smoothing” exercise inherently assumes that actual deviations from a*
6 *smoother load profile represent changes actively provided by PHP rather*
7 *than operational variations that might be entirely independent from system*
8 *conditions. Consequently, the risk of incorrectly estimating the DR credit*
9 *would likely be biased toward overestimation, to the detriment of FAM*
10 *customers.*

11 And at p. 28, lines 14-21:

12 *We do not recommend that the Board approve the DR credit as proposed. To*
13 *be reasonable, at least two things must be true: (1) any payments to PHP*
14 *from FAM customers under the DR credit must demonstrably tied to PHP*
15 *deciding to shift load due to energy prices and (2) that FAM customers not*
16 *be at risk of providing any compensation to PHP in hours where no load-*
17 *shifting activity due to energy prices occurred. It may be that, with additional*
18 *elaboration, revisions, reporting requirements, and verifiability guardrails,*
19 *the mechanism may achieve these objectives, but as proposed, it is our view*
20 *that the DR credit is too vague, uncertain, unverifiable, and at risk of failing*
21 *to match rider payments to load-shifting service to be recommendable for*
22 *approval.*

23

24 (a) Bates White identifies six concerns with the DR credit and recommends it
25 not be approved as proposed. Please confirm whether in Bates White’s
26 view all six concerns should be resolved before the DR credit can be
27 approved in any form, or would resolution of a subset suffice? If a subset
28 would suffice, please identify which concerns are threshold requirements
29 for approval.

30 (b) Please describe, as precisely as possible, the specific elaborations,
31 revisions, reporting requirements, and guardrails Bates White considers as
32 the minimum necessary to make the DR credit approvable, addressing
33 each of the six stated concerns in turn.

34 (c) Where there is a bias toward overestimation because load smoothing
35 attributes all deviations from the CBL to price-responsive behaviour, does
36 Bates White agree that this structural bias cannot be fully eliminated by any

guardrails or reporting requirement?

(d) Under the current ELIADC tariff, load shifting savings are shared 75% to other customers and 25% to PHP. Does Bates White agree that:

(i) The 75/25 benefit-sharing arrangement served as a structural buffer that limited the damage to other customers from CBL overestimation; and

(ii) Removing that buffer entirely, by moving to a 100% allocation to PHP, materially increases the exposure of FAM customers to the consequences of overestimation? If not, please explain.

(e) Does Bates White agree that with a benefit-sharing arrangement, even if the CBL overestimates PHP's contribution, FAM customers retain a portion of the calculated savings as a hedge against that overestimation?

(f) The Bowman evidence (Exhibit N-25) at p. 12 identifies two potential amendments to the structure of the tariff to address the overestimation risk: either amend the CBL to better reflect PHP's expected seasonal load (e.g., reflective of the paper market order book) or retain a benefit-sharing arrangement. Does Bates White have any objection in principle to a form of benefit-sharing approach as is currently in place under the ELIADC (75/25 in favour of other customers) being carried forward into the ELID DR credit? Please explain.

(g) If Bates White does object, please explain what specific objections make a 100% allocation to PHP preferable to benefit-sharing, given Bates White's concern regarding the bias toward overestimation.

Response IR-10:

(a-b) Please see our response to BW-IG IR-7 (b).

1 (c) It is unlikely that guardrails and/or reporting requirements can fully eliminate structural
2 bias assumed and referenced in the request.

3 (d)

4 (i) Yes.

5 (ii) Yes.

6 (e) Yes.

7 (f) No.

8 (g) Not applicable.

1 **Request IR-11:**

2 **Reference: N-20, Bates White Evidence, p.8, lines 22-24:**

3 *In addition to correcting the Energy Charge rates, we recommend that a true-*
4 *up mechanism be created to address substantial deviations of PHP net load*
5 *from expectations — including the extreme but plausible scenario in which*
6 *PHP's annual net load subject to the tariff rate is zero.*

7 **And p. 33, lines 10 - 18:**

8 ***Q. Is there a potential scenario in which PHP has zero net load subject to the***
9 ***ELID Energy Charge?***

10 ***A. Yes. As discussed above, the 653 GWh of output from Goose Harbour is***
11 ***a reasonable estimate of potential generation from the full 168 MW facility,***
12 ***and in fact is conservative, since that is a P90 level that is expected to be***
13 ***exceeded 9 years out of 10. The PSA anticipates that PHP load fall below 625***
14 ***GWh, as that is the established threshold below which the Sales Agreement***
15 ***Fee increases from \$2.00/MWh to \$4.00/MWh. Thus, there is a very plausible***
16 ***scenario in which PHP would have annual net load of zero under the ELID***
17 ***tariff, and would pay no Energy Charge at all, and cover none of the***
18 ***embedded costs reflected in the Energy Charge.***

19 (a) Please specify the threshold deviation of PHP net load from the COSS-
20 modelled level that Bates White considers sufficient to trigger the true-up
21 mechanism.

22 (b) Please describe the methodology Bates White proposes for calculating the
23 true-up amount — specifically:

24 (i) Would the true-up apply only to the shortfall in Energy
25 Charge revenue collections, or also to the embedded fixed
26 cost allocation shortfall caused by understating PHP's net
27 load in the rate-setting COSS; and

28 (ii) Would the true-up amount be recovered solely from PHP, or
29 spread across all ATL customers?

30 (c) Bates White identifies a zero net load scenario, where Goose Harbour
31 generates more energy than PHP consumes. Please confirm that in this
32 scenario, PHP would pay no Energy Charge, make no contribution to
33 embedded cost recovery, and yet remain connected to and served by the
34 NSPI system?

(i) How could a true-up mechanism be designed to address this scenario specifically?

(d) Does Bates White recommend that the true-up mechanism be scoped and approved as part of any approved ATL tariff for PHP?

Response IR-11:

(a) Our recommended true up would address the potential adverse effects of PHP net load treatment on recovery of costs to serve PHP. The true-up mechanism would therefore require assessment of whether costs were appropriately recovered, and would not depend on any particular net load deviation

(b) We are not proposing a specific true-up calculation methodology.

(i) A true-up should address the full cost to serve PHP load, inclusive of an allocation of embedded fixed costs. Any true-up methodology would have to assess the appropriate share of fixed costs – e.g., excluding the notional treatment of Goose Harbour generation in one period offsetting PHP load in other periods.

(ii) The true-up we propose would be specific to the ELID tariff and PHP.

(c) Confirmed that that is our understanding of how the proposed ELID tariff would function in combination with the Goose Harbour PSA.

(i) As noted in response to IR-11 (b)(i), a true-up would have to determine how PHP load was actually served, excluding purely notional treatment of Goose Harbour output as an offset to PHP load.

(d) Yes.

Request IR-12:

Reference: N-20, Bates White Evidence, p. 8, lines 10-20:

Perhaps most disruptive to recovery of fully embedded costs under the ELID, the PSA allows PHP to 'bank' excess Goose Harbour output, magnifying PHP's ability to avoid tariff energy charges by applying Goose Harbour generation in one period to offset tariff purchases in a later period. The PSA also allows PHP to claim unproduced, curtailed energy to reduce tariff purchases. Finally, the PSA fails to adjust Goose Harbour energy deliveries for transmission losses. Instead, the project is treated as a behind-the-meter resource, when in fact that project is not located behind the meter, but rather is part of the grid — and generating transmission losses — the cost of which will be borne by FAM customers.

To be clear, we are not taking issue with the terms of the PSA. Those terms are undoubtedly advantageous and preferential to PHP, but our concern in this Evidence is the disruptive effect of the PSA on the likelihood of PHP paying its properly allocated embedded costs as an ATL customer under the ELID.

(a) In relation to each of the three features of the PSA which Bates White identifies as disruptive to proper cost recovery, please discuss whether it is inconsistent with PHP's premised status as a fully ATL customer paying properly allocated embedded costs:

(i) Banking of excess output;

(ii) Credit for curtailed but unproduced energy; and

(iii) No transmission loss adjustment.

(b) Should all three disruptive features and not merely the 130.5 MW versus 168 MW capacity error be reflected in a corrected COSS before the Energy Charge rates can be approved, and if so, how?

Response IR-12:

(a) We find all three noted disruptive features to be inconsistent with the premised treatment of PHP as a “fully ATL customer playing properly allocated embedded costs.”

(i) See above.

(ii) See above.

1 (iii) See above.

2 (b) We acknowledge an intent to provide PHP with the benefit of output from Goose
3 Harbour. This could be done without the “net load” treatment applied in determining the
4 ELID Energy Charge. One substantial improvement to the ELID would be to eliminate
5 the effective banking of excess Goose Harbour generation and instead better link Goose
6 Harbour’s hourly output to PHP’s hourly load, compensating PHP for any hourly Goose
7 Harbour generation in excess of PHP load in the same hour, accounting for system
8 conditions and transmission losses.

Request IR-13:

Reference: N-20, Bates White Evidence, p. 32 Table 4: Effects of Goose Harbour Generation Treatment Under the PSA on PHP Energy Costs for 2027.

Preamble: In Table 4, and at p. 33 Bates White calculates that in an alternative scenario of 774 GWh PHP gross load and 653 GWh Goose Harbour output, PHP's tariff payments to NSPI would be reduced by \$20.6 million and net energy cost would be approximately [REDACTED] million lower than under COSS assumptions, because excess Goose Harbour generation displaces tariff energy at the embedded cost rate rather than the \$80/MWh PSA rate.

(a) Does this outcome effectively allow PHP to sell excess wind generation back to FAM customers at embedded cost rates?

(i) If so, does this create an unintended subsidy from those customers? If not, please explain.

(ii) If so, is any such subsidy consistent with the premise that PHP is a fully ATL customer?

(b) At p. 29, Bates White quotes NSPI's application that excess Goose Harbour output in a given month "will be carried forward to be applied to PHP consumption in a future billing period." Does this banking feature mean that essentially all Goose Harbour generation, regardless of when it is produced, will reduce PHP's tariff obligations, making hour-by-hour matching of generation to load irrelevant?

(c) In Bates White's opinion is this approach to rate setting compatible with the premise of PHP as an ATL customer paying for grid energy it actually consumes? Please explain.

Response IR-13:

(a) Yes

(i) This will generally create a subsidy from FAM customers to PHP

(ii) No.

(b) Yes.

- 1 (c) No. Allowing banking of Goose Harbour generation as an offset to non-
- 2 contemporaneous PHP load is not generally consistent with PHP covering the actual
- 3 cost to serve its load.

1 **Request IR-14:**

2 **Reference:** N-20, Bates White Evidence, p. 35, lines 15-17 and p. 36, lines 1-3,

3 **Recommendations:**

4 *Given the potential for variable Goose Harbour generation to have significant*
5 *effects on cost recovery — to the potential disadvantage of PHP as well as*
6 *FAM customers — we recommend that NSPI evaluate cost recovery under*
7 *the ELID tariff at the conclusion of each annual period.*

8 **And:**

9 *We also recommend NSPI explain the methodology for tracking the costs of*
10 *administering the ELID Tariff and how NSPI plans to ensure that 100% of the*
11 *costs incurred above in administering the ELID Tariff are paid by PHP,*
12 *including those above the Customer Charge collections.*

13 (a) Would Bates White agree that quarterly reporting of key metrics (year-to-
14 date DR credit accrual estimates, actual Goose Harbour output versus
15 COSS-modelled levels) would be helpful to allow meaningful monitoring
16 before material over- or under-recovery has fully crystallized? Please
17 explain why or why not.

18 (b) Please confirm whether the recommended annual evaluation and true up
19 are intended to operate in parallel or whether the true-up mechanism is
20 intended to replace one or more elements of the annual evaluation.

21 (i) Specifically, would the true-up mechanism automatically
22 correct for Goose Harbour over-generation, or would the
23 annual evaluation be required first to determine whether the
24 true-up threshold has been triggered?

25 (ii) If both mechanisms operate in parallel, please describe how
26 they are sequenced in a year where Goose Harbour output
27 significantly exceeds the COSS-modelled level.

28 (c) Does Bates White agree that the Board should specify, as conditions of
29 approval, the following minimum reporting obligations: (i) monthly or
30 quarterly reporting of actual Goose Harbour output versus the COSS-
31 modelled level; (ii) quarterly estimates of the year-to-date DR credit
32 accrual, including identification of any discretionary adjustments made by

1 NSPI; and (iii) annual reporting of actual Customer Charge administration
2 costs against the eight identified tasks?

3 (i) If Bates White does not support quarterly reporting for items
4 (i) and (ii), please explain what reporting frequency it
5 considers adequate and why.
6

7 **Response IR-14:**

8 (a) Our recommendation is for cost recovery to be assessed annually. Quarterly reporting
9 of the noted metrics would be useful.

10 (b) The proposed true-up would be to address cost recovery discrepancies identified in the
11 annual review process.

12 (i) The proposed true-up mechanism would address cost recovery and would not
13 necessarily entail any “automatic” correction for variation in Goose Harbour generation.

14 (ii) See (i).

15 (c) We have not recommended such specific reporting requirements. We would not oppose
16 them.

17 (i) See above.