M12665

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF: The ***PUBLIC UTILITIES ACT***

-and-

IN THE MATTER OF: A public hearing for **NOVA SCOTIA POWER INCORPORATED'S** Fuel Adjustment Mechanism (FAM) Audit for 2024/2025 by Bates White Economic Consulting, LLC

INFORMATION REQUESTS

To: **Blake Williams**
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From: The Consumer Advocate

Responses Due: **Tuesday, November 17, 2026**

Copies: 1 electronic copy (PDF searchable)

Contact Person: **David J. Roberts**
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Request IR-1:
Please identify each instance where the FAM Audit states that the cyber event required a material change in job duties. For each instance, please state whether you are aware of any increased cost or deferral of ongoing projects that occurred as a result of the change. Where possible, quantify the cost that increased or the cost that occurred during a period of project deferral. Note that this question is being addressed to both Bates White and Nova Scotia Power. If only one party provides some or all of the responses, the other party should state whether it is in agreement with some or all of the responses. If one of the parties is not able to express its opinion for any response, it should explain why.

Request IR-2:
The FAM Audit states:

> Wind and hydroelectric monthly production is estimated outside of PLEXOS, based on historical information and entered into PLEXOS. Monthly wind energy production profiles are based on averages of the last three years' production data for each telemetered wind project or based on the geographically nearest telemetered wind site. The hourly wind generation profiles are based on the previous year hourly wind profile coincident with the hourly load profile and input into PLEXOS together with monthly energy and peak generation forecast information for each wind generator. Hydroelectric production estimates for each unit use a 23-year rolling average, adjusting the average for unit additions, decommissioning, and extended unavailability for inspections and maintenance. Historical monthly hydro system energy averages are qualified in PLEXOS by the daily and weekly production restrictions representing water flow restrictions and reservoir capabilities including, riparian flows, fish ladder flows, required reservoir levels, etc. The run of river systems are modeled as fixed output profiles to represent the non-dispatchable nature of such systems. As we have pointed out in the past, the use of historical hydroelectric production data to forecast production from these resources assumes a certain regularity in Nova Scotia weather patterns which may not hold true over the long term. (p. 57)

In Exhibit N-4, CA RIR-2, M11533, Bates White stated that, "It is standard practice for utilities to consider weather conditions in short-term operational forecasts; weather can strongly impact customer demand, and can also dictate energy supplied from renewable energy sources such as wind or solar."

This question considers whether the use of historical data *only* in PLEXOS for fuel and purchased power forecasting as compared to the use of either forecast or recent data when making decisions about fuel procurement (e.g., coal or HFO deliveries), unit commitment, and maintenance schedules in an annual and quarterly planning context (FAM Audit, p. 57).

For further context, a recent scientific journal article suggests that certain weather forecast models "show promise in capturing large-scale modes of variability that are important for seasonal and subseasonal forecasting." Pia Leminski, Enzo Pinheiro, and Taha B. M. J. Ouarda, Ensemble of

Artificial Neural Networks for Seasonal Forecasting of Wind Speed in Eastern Canada, *Energies* 2025, 18(11), 2975; https://doi.org/10.3390/en18112975.

(a) Please confirm that NS Power relied exclusively on historical information to produce monthly wind and hydroelectric production. (See also Exhibit N-4, CA RIR-3(a), M11533.) If not confirmed, please clarify in detail.

(b) During periods of wind or hydroelectric drought that may have occurred during the audit period, did NS Power make any adjustments to these monthly forecasts? If not, how are hydroelectric production restrictions forecast without taking existing reservoir conditions and anticipated rainfall into consideration?

(c) With respect to short-term operational dispatch planning, did NS Power consider weather conditions in its forecast of wind, solar and hydroelectric generation during the audit period? If so, over what timescale and for what specific purposes?

(d) Are you aware of any enhancement in related capabilities that has occurred since the audit period or that may be planned (or under consideration) by NS Power or IESO Nova Scotia? If so, please describe.

(e) Considering the concepts discussed in the referenced scientific journal article, are you aware of any commercially-available products that could provide useful seasonal (e.g., monthly) forecasts of wind and hydroelectric production? If so, please discuss these products and the potential relevance to future use in Nova Scotia.

(f) Considering the planned growth in wind resources through 2030, would it be advisable for NS Power or IESO Nova Scotia to consider changes to the practices discussed in this question? If so, please elaborate.

Request IR-3:

The FAM audit describes NSPI's single largest contingency as 168 MW, Point Aconi's net output. (p. 60). According to the IESO NS 2026 10-Year Outlook report, there are two requests for load interconnection with facility peak demand in excess of 168 MW (230 MW and 325 MW). (Exhibit N-4, NSEB RIR-15)

(a) In your opinion, is it likely that interconnection of these facilities would result in an increase of the single largest contingency for operating reserve purposes, at least for Regulation-Down purposes? Explain your response.

(b) If the Regulation-Down requirement is increased, what would be likely changes to:

i. Operational practices?

ii. System planning needs?

(c) Do you believe that either NS Power or IESO Nova Scotia needs to begin planning for this possibility in advance of a signed contract (or its equivalent) indicating a customer commitment to take service?

Request IR-4:
On p. 103 of the FAM Audit, a meeting to discuss safety issues is described as occurring on December 6, prior to three of the four safety violations mentioned.

(a) Why is a mistake in hauling ash instead of coal considered a "safety violation" rather than failing to meet some other category of contract requirement?

(b) Considering that ash hauling was not part of this company's contract (see p. 115), did NS Power determine how its staff allowed the truck to load ash and take any remedial steps with NS Power staff or practices?

(c) Considering that the ash hauling incident was the only cited event that occurred before December 6, were there other indications that prompted NS Power to schedule the December 6 meeting?

Request IR-5:
On p. 112, Bates White states that the track between PTMT and Trenton is on land owned by Nova Scotia Lands. Who owns the track and is there a payment to Nova Scotia Lands for use of the land?

Request IR-6:
On p. 127, there is a discussion of the E-Crane.

(a) When was the E-Crane last used?

(b) Please confirm that the E-Crane is not expected to be used in the future. If not confirmed, please explain under what conditions it may be placed back into active service.

(c) If part (b) is confirmed, please explain why this asset has not been retired and decommissioned.

Request IR-7:
On p. 127, there is a discussion of the settling ponds at the International Pier.

(a) Please identify all recent events where coal fines were not adequately settled out during heavy rain events, including the FAM audit period but extending back further several years to the extent that this issue was not reviewed during previous FAM audits.

(b) Please explain the environmental consequences of inadequate settling of coal fines.

(c) Please identify each of the events referenced in your response to part (a) that resulted in any regulatory action (inspection, compliance penalty, etc.), describe the action, provide any resulting costs to NS Power, and identify whether those costs were booked to FAM.

Request IR-8:
Please provide copies of the Root Cause Analyses reviewed by Bates White (Figure X-16, FAM Audit, p. 257).

Request IR-9:
On p. 109 of the FAM Audit, the cost to scrap railcars is redacted. Why is this cost considered confidential?

Request IR-10:
Regarding the biomass fuel handling issue beginning on October 30, 2024 (p. 170), Bates White explains that after the event, NS Power implemented "a revised storage configuration that uses smaller and lower height biomass fuel storage piles, rather than fewer larger piles, in order to improve ventilation and reduce compaction in the piles" (p. 171).

(a) Were the larger storage piles a long-term practice prior to October 2024? If so, what changed to cause the hot spots? If not, how did this practice develop?

(b) Is it well understood that, in general, larger biomass storage piles are more likely to develop hot spots, potentially leading to fire, than smaller piles? If your answer is anything other than an unequivocal yes, please explain how increasing the size of a storage pile will not increase the potential for development of hot spots.

Request IR-11:
Regarding NS Power's rejection of Recommendation VI-6:

(a) Please confirm that the deficit occurred as a result of PHP bark deliveries to the piles that feed the boiler rather than transfers to fuel storage piles in the yard. If not confirmed, please explain.

(b) The FAM Audit report states that PHP made up the bark deficit "as of May 2026." Was this accomplished by gradual deliveries to the piles that feed the boiler or a transfer of fuel from PHP to NS Power's fuel storage piles in the yard?

(c) If PHP delivers bark in excess of operational requirements, under what circumstances would NS Power not be able to adjust its delivery of bark to the piles that feed the boiler?

(d) If NS Power can generally adjust its delivery of bark to the piles that feed the boiler, why would there be increased fuel handling costs and yard congestion?

(e) If the deficit occurred as a result of PHP bark deliveries to NS Power's fuel storage piles in the yard, please explain why this did not lead to the same increased fuel handling costs and yard congestion that would occur as a result of reducing the deficit, or vice versa in the case of a surplus.

(f) Please explain the circumstances that would lead to "elevated risk of spontaneous combustion."

(g) Please provide NS Power's opinion on a "collar" approach, in which a certain amount of bark deficits are allowed, and beyond which the "enhancement" recommended by Bates White would be applied.

Request IR-12:
Regarding low pressure events on the natural gas pipeline lateral (FAM Audit, p. 258, 325), please provide any analysis NS Power has done regarding the frequency of these events and the potential that they may increase due to expansion of Eastward Energy's service territory or the hybrid winter heating strategy. If no such analysis has been conducted, why not?

Request IR-13:
Please provide the estimates of FAM costs referred to in Recommendations X-2, 3, 5, and 6. If not yet available, please explain why not.

Request IR-14:
Please clarify your response to Recommendation X-3, is NS Power committing to remove the FAM costs (forthcoming estimate) from the FAM balance? If not, please explain how NS Power will ensure that FAM customers bear no incremental costs for the outage.

Request IR-15:
With respect to Recommendation X-4, please provide an update on the status of corrective measures and any further insights into the causes of the Point Tupper October – November 2024 outage.

Request IR-16:
The FAM Audit, discussing a forced outage at Port Hawkesbury Biomass, identifies both FAM costs due to the event and the cost of repairs to the broken Rod in Recommendation X-6. How long did the repairs to the broken Rod take from when the decision was made to undertake temporary repairs?

Request IR-17:
The FAM Audit, discussing hedging costs, states that "NSPI also incurs interest costs and received interest revenues associated with its capital markets margin account where much of its hedging activity takes place. However, these costs and revenues are not FAM costs/revenues." (p. 426)

(a) Please explain whether and, if so, how NS Power recovers costs and receives revenues associated with its capital markets margin account.

(b) If NS Power recovers these costs from customers, please provide a summary of those costs/revenues for each year in the audit period. If possible, provide the summary as an actual or estimated allocation by class, including both above and below the line customer groups, as applicable. If allocation is not possible, please explain why not.

Request IR-18:
The FAM Audit states, "PHP's load as represented in PortOps is not fully dispatchable in every hour – i.e., from zero to maximum load – but is subject to various constraints based on defined

operating modes ("OMs") for the PHP facility, including consideration of available pulp storage over time." (Exhibit N-5, p. 442) In its reply evidence, NS Power states that, "the PortOps optimisation model does not explicitly model PHP transitioning through intermediate operating modes to reach the desired operating state." (Exhibit N-8, p. 22)

(a) Please address any inconsistencies between these two statements.

(b) Please explain why NS Power did not configure PortOps to model PHP transitioning through intermediate operating modes. In your answer, please specifically address the example provided in your response to Recommendation XV-5 describing a 3-hour ramp period (Exhibit N-8, p. 23).

Request IR-19:

NS Power's Reply Evidence states,

> NS Power also notes that, for PHP initiated deviations from forecast, including unilateral deviations from the approved dispatch profile (Cause Code 5), deviations are recorded for each hour in which the deviation remains in effect and continue to be tracked until the next system dispatch optimisation forecast is issued. It is only for NS Power initiated ramp up and ramp down requests that deviations are recorded in the hour in which the request is initiated and not during the subsequent hours required for PHP to achieve the requested operating level. This distinction recognises that these deviations arise from NS Power's dispatch decisions in real time and the physical limitations associated with implementing those decisions, rather than from a failure by PHP to respond to dispatch instructions. (Exhibit N-8, p. 23)

(a) Please explain what NS Power means by "physical limitations," including specifically whether NS Power views physical limitations to be bounded by the duration of PHP's response.

(b) If in NS Power's example of a 3-hour ramp, PHP took 5 or more hours to ramp to the optimal dispatch level, would NS Power:

i. Record a deviation *only* in the hour in which the request is initiated, or

ii. Also record a deviation in later hours when the ramp did not reach the optimal dispatch level in a timely manner?

(c) Please provide any relevant operating guidance or other documentation supporting the reporting practices described in your answers to part (a) and part (b). If none exists, explain how these practices are maintained consistently (e.g., through operator or other staff training or common understanding).

(d) In the 2019 ELIADC tariff application, NS Power stated, "In order to take service under the ELIADC Tariff, PHP will be required to effectively turn over control of the scheduling

of its operations to NS Power. NS Power will schedule the timing and magnitude of PHP's electricity usage within an agreed set of protocols." (Exhibit N-1, Application, M09420, p. 22)

i. Please confirm whether NS Power is dispatching PHP like a power plant.

ii. Please explain whether there are any differences of scope or kind between the Active Demand Control protocols and the types of considerations at other dispatched power plants on NS Power's system. In other words, would it be reasonable to expect to find the types of considerations included in the protocols in the dispatch practices used for any other utility-owned or contracted power plant?

Request IR-20:

In its submission to the ELIADC tariff extension application proceeding, Bates White states that,

> NSPI and PHP have relied on bilaterally-determined top up payments by PHP of an amount and at a time determined by NSPI and PHP. These payments are not contemplated in the ELIADC Tariff, nor are there any specific reporting requirements associated with these payments. NSPI does not formally report these payments to the Board and stakeholders until NSPI files its annual report on the ELIADC Tariff the following year. (Bates White, Submission (June 10, 2025), M12184, p. 11)

(a) Please confirm the accuracy of this characterization, or provide clarification as necessary.

(b) Please briefly describe the CBL Energy Charge and the tariff language describing how it may be adjusted, including both the basis on which NS Power may propose adjustments and the process for implementing those adjustments.

(c) Please provide an accounting of the "top up" payments made during the audit period and support for their calculation.

(d) Why does NS Power consider the "top up" method appropriate?

(e) Why did NS Power not propose adjustments to the CBL Energy Charge during the audit period?

Request IR-21:

NS Power's Reply Evidence states, "NS Power does not believe that hourly measurement of real time deviations provides a reliable indication of demand response performance." (Exhibit N-8, p. 24) The evaluator for EfficiencyOne's demand response program uses "a model that predicts the expected average hourly load per participant and then compared the expected and actual hourly loads during events." (Exhibit E-2, M12186, Econoler, Demand Response Program: Final Appendix Report, 2024 DSM Evaluation (March 25, 2025), Appendix 2, pdf p. 1034)

(a) Please reconcile NS Power's statement with typical demand response program evaluation methods.

(b) Please explain what quantitative method NS Power suggests is a reliable indication of demand response performance under the ELIADC tariff, and identify or provide the results of this measurement.

(c) If NS Power is not able to provide a method and quantitative results in response to part (b), please explain how customers are assured that cost savings have occurred as a result of ELIADC dispatch methods.