NEW BRUNSWICK
ENERGY & UTILITIES BOARD

COMMISSION DE L'ÉNERGIE ET DES SERVICES PUBLICS
NOUVEAU-BRUNSWICK

**REASONS FOR DECISION**

**IN THE MATTER OF** a review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology.

(Matter No. 554)

April 2, 2025

**Matter 554 – NB Power Class Cost Allocation Study Methodology**

**IN THE MATTER OF** a review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology. (Matter No. 554)

**APPLICATION:** December 15, 2023
**ORAL HEARING**: October 22 to 24 and November 7, 2024

**NEW BRUNSWICK ENERGY AND UTILITIES BOARD**:

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| Chairperson | Christopher Stewart |
| Member | Heather Black |
| Member | Kenneth McCullogh, K.C. |

**PARTICIPANTS**:

| | |
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| New Brunswick Power Corporation | John Furey |
| J.D. Irving, Limited | Glenn Zacher |
| Utilities Municipal | Ryan Burgoyne |
| **PUBLIC INTERVENER**: | J.M. Alain Chiasson |

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**Matter 554 – NB Power Class Cost Allocation Study Methodology**

## 1 Introduction and Summary Conclusions

[1] These are the reasons for the Board's oral decision of December 19, 2024 by which NB Power was directed to modify the classification and allocation of costs in its class cost allocation model to accord with the Alternative #1 Seasonal CCAS model from Matter 357 and 529 and to use the resulting model to develop evidence of revenue-cost ratios beginning with its next general rate application. The decision was the result of the Board's review of NB Power's generation class cost allocation methodology, including seasonal cost differences and other issues that may be creating inequity in the utility's rate structure. The review was prompted by the Board's concern that an inequitable class cost allocation methodology could impair its ability to assess NB Power's rate design proposals.

[2] The Board intends to consider further class cost allocation methodological changes as part of the Phase 2b rate design proceeding.

## 2 Overview

[3] On the motion of J.D. Irving, Limited in Matter 529, the Board expressed concern that the cost allocation methodology being used by NB Power could be creating inequities among rate classes and determined that a review of NB Power's cost allocation methodology including, but not limited to, consideration of seasonal cost allocation was appropriate. This matter arises out of that concern and relates specifically to the equitable allocation of the generation component of the cost of providing electricity service among NB Power's various customer classes.

[4] The cost of providing electricity service may differ among different classes of customers. Furthermore, the cost of generation may vary from season to season and by time of day. It is a generally accepted regulatory principle that each class of customer should pay its fair share of the cost of electricity service.

[5] The class cost allocation study ("CCAS") is a method by which a utility's revenue requirement is assigned to rate classes in accordance with the costs caused by each class. On a system-wide basis, the revenues collected through approved rates from all customer classes should ideally be equal to the sum of the costs assigned to each class, resulting in a system revenue-cost ratio of 1.0 (or 100%). On a class-by-class basis, the Board has historically considered a revenue-cost ratio between 0.95 and 1.05 to be equitable because rates charged to each class produce projected revenues that approximate the costs allocated to that class.

[6] A CCAS generally follows a three-step process. First, costs are functionalized according to the broad investment and operational areas of the utility. For costs functionalized as generation costs that are examined in this matter, the second step involves classifying generation costs as either demand-related or energy-related. The final step allocates those costs among the customer classes based on the principle of cost causation.

[7] Typical demand-classified generation costs include most capital costs of generation plants. Demand-classified costs vary with the highest amount of consumption over a specified period and are allocated based on the demand imposed on the system by each class during specific peak hours. The most obvious energy-related costs are fuel costs. These and other costs that vary directly with the quantity of energy produced are known as variable costs, while other costs associated with the utility's generating plant are known as fixed costs. Energy-classified costs may include fixed costs that are indirectly related to the quantity of energy produced, such as capital costs that reduce fuel costs. Energy-classified costs are allocated based on the volume of energy provided to each customer class.

[8] NB Power developed its current CCAS model using the Average and Peak methodology. The Average and Peak methodology classifies all fixed generation costs as demand-related or energy-related based on the system load factor, calculated as a ratio of the average demand to the average of the three winter months ("3CP"). Energy-classified fixed costs and all variable costs are allocated based on annual average demand, while demand-classified fixed costs are allocated based on the percentage of 3CP attributable to each class.

[9] This matter was heard October 22 to 24 and November 7, 2024. Appendix A lists the parties to this proceeding and describes each witness who gave written and oral testimony. NB Power, J.D. Irving, Limited, Utilities Municipal, and the Public Intervener made witnesses available for cross-examination during the oral hearing.

[10] As discussed at the procedural conference in this matter on June 28, 2023, NB Power has submitted four CCAS models for consideration. The first follows the current Average and Peak methodology. The other three were time differentiated models using the Average and Peak with Time of Use methodology, the Probability of Dispatch methodology, and the Marginal Cost methodology.

[11] The Average and Peak with Time of Use methodology modeled by NB Power classifies all fixed generation costs as demand-related or energy-related based on the system load factor. Energy-classified fixed costs and variable costs are allocated to each hour based on total dispatch cost in that hour. Demand-classified fixed costs are allocated to each

hour based on the probability of a loss of load due to inadequate capacity. Hourly costs are then allocated to customer classes based on the customer class load in each hour.

[12] The Probability of Dispatch methodology modeled by NB Power allocates variable costs identically to the Average and Peak with Time of Use methodology. Fixed generation costs are jointly classified and allocated based on dispatch of each generating station in each hour. The fixed costs of each resource are allocated to all hours when the resource is generating energy or supplying operating reserves, in proportion to the production of that hour. Hourly costs are then allocated to customer classes based on the customer class load in each hour.

[13] The Marginal Cost methodology modeled by NB Power allocates energy, capacity, and greenhouse gas marginal costs to each customer class. The total marginal cost is reconciled upwards or downwards to match the total revenue requirement. Marginal variable energy costs are calculated by hour. The marginal cost of capacity is allocated to each hour based on Loss of Load Probability and then allocated to customer classes based on the customer class load in each hour. NB Power included this model in its evidence for information purposes and does not consider it appropriate for the utility's CCAS.

[14] For each methodology, NB Power modeled revenue-cost ratios for the Fiscal Years ended 2024 and 2034 using the existing rate classes and new rate classes that had been proposed in Matter 529.

[15] NB Power also submitted two updated sensitivities that had been developed for use in Matters 357 and 529 to add seasonal elements to its current Average and Peak methodology: a Main Seasonal Sensitivity, which accounts for seasonal cost differences in energy-classified fixed and variable costs and an Alternative #1 Seasonal Sensitivity, which accounts for seasonal cost differences only in variable costs.

[16] NB Power proposes to continue using the Average and Peak methodology without seasonal sensitivities to develop its CCAS. Utilities Municipal support NB Power's proposal. JDI opposes the status quo on the grounds that the Average and Peak methodology is insufficiently time-differentiated to reasonably represent cost causation and requested several methodological modifications. The Public Intervener does not advocate for the adoption of any particular methodology but filed evidence reviewing each option's advantages and disadvantages and attempting to achieve internally consistent logic within the CCAS.

[17] NB Power maintains that the Average and Peak methodology it now uses should be maintained for the time being. However, it concedes that the Probability of Dispatch

methodology would be a reasonable alternative to the continued use of the Average and Peak methodology after it has completed its migration from its current power generation and transmission modeling system (PROMOD) to a more capable simulation platform (PLEXOS). In the near term, JDI considers the current Average and Peak methodology with the Alternative #1 Seasonal Sensitivity to be acceptable, with some modifications.

## 3 Issues

1. What criteria should the Board use to evaluate alternative methodologies?

2. Which model best satisfies the criteria?

3. What are the next steps in cost allocation and rate design for NB Power?

## 4 Criteria include cost causation, modeling capability, and transparency

[18] The Board views cost allocation as an essential component of rate design and the foundation for establishing just and reasonable rates. Just and reasonable electricity rates should be structured to reflect the cost of providing service to the utility's customers, except as may be necessary to accommodate overriding regulatory objectives.

[19] According to the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual, which the Board has relied on in previous decisions, no major cost allocation methodology is superior to another, the choice of methodology will depend on the utility's unique circumstances, and individual methodologies are complex and are subject to debate. The expert evidence supports these statements. Mr. Bowman and Mr. Knecht agreed that no methodology perfectly reflects cost causation and no objective measure exists against which to compare methodologies. Mr. Knecht and Mr. Ming described the advantages and disadvantages of the methodologies offered for the Board's consideration. Mr. Knecht also testified that in his opinion, each of the four methodologies and two sensitivities NB Power offered for the Board's consideration is based on recognized cost allocation methodologies described in the NARUC Manual and are all reasonable in a broad sense.

[20] NB Power's cost allocation methodology should reflect cost causality in the context of its unique circumstances. The cost of serving NB Power's customers is higher at certain times of the year and day. NB Power has a winter-peaking electricity system with its load shape substantially determined by the space heating needs of the Residential and General Service rate classes. Serving these customers drives the utility's system planning and the costs it incurs to meet capacity and energy needs during peak hours and throughout the colder months. Peak demands occur entirely in the winter period on the coldest days and

electricity consumption is much higher in the winter months than at other times of the year.

[21] The Board's objective in this matter is to approve a CCAS methodology that can be used to evaluate rate design proposals in upcoming proceedings, making NB Power's modeling capability a relevant consideration. Since PROMOD is not capable of simulating the time-differentiated methodologies, Elenchus, relying on E3's modeling, endeavored to model the Average and Peak with Time of Use, Probability of Dispatch, or Marginal Cost methodologies with available data for the fiscal years 2024 and 2034 using current and proposed rate classes. NB Power's plan to migrate to a new simulation platform (PLEXOS) as early as April 2027 could make time-differentiated modeling available in the future.

[22] Ms. Zarnett urged the Board to consider several factors including transparency, data requirements and ease of implementation. She recommended the Board avoid cost allocation choices that may be biased towards certain customer classes or to a particular rate structure outcome. The Board agrees. The Board also agrees with Mr. Zacher's submission that rate design considerations should not be a barrier to accurately assessing and allocating costs.

[23] The criteria for selecting from among the various recognized, if imperfect, CCAS methodologies should include:

a. whether the methodology is consistent with the regulatory principle that each class of customer should pay its fair share of the cost of electrical service, including the extent to which the methodology recognizes time differentiated costs

b. whether NB Power's present modeling system provides sufficient data for accurate modeling using the methodology

c. the degree of transparency possible using the methodology

## 5 The Alternative #1 Seasonal Sensitivity best satisfies these criteria

[24] On behalf of NB Power, Mr. Furey submitted that the Board should approve the retention of the Average and Peak methodology unless the evidence indicates that another methodology demonstrably captures cost causality in a better way. To the extent he was suggesting that there is a sort of rebuttable presumption that the current methodology is best, the Board cannot agree. The Board's obligation to fix just and reasonable rates requires it to consider the evidence before it and to apply its judgment and discretion in

selecting a CCAS that the Board determines best reflects cost causality and satisfies the other criteria.

### 5.1 Average and Peak and its Seasonal Sensitivities can be modeled now

[25] NB Power's current modeling system (PROMOD) does not provide sufficient data to confidently assess the impact of using any of the Average and Peak with Time of Use methodology, the Probability of Dispatch methodology, or the Marginal Cost methodology. For now, and the near future, only the existing Average and Peak methodology and the Seasonal Sensitivities can be fully modeled and implemented. The Board concludes that NB Power's planned migration to PLEXOS by April 1, 2027, does not justify retaining the existing Average and Peak methodology because the migration is not expected to be completed in time to inform the upcoming rate design proceedings and may be delayed by unforeseen difficulties.

[26] NB Power filed Elenchus models of the Average and Peak methodology and the Main and Alternative #1 Seasonal Sensitivities for the Fiscal Year 2024 using the current and proposed rate classes. On behalf of JDI, Mr. Zacher noted that NB Power did not file modeling for Fiscal Year 2034 for the Seasonal Sensitivities, nor did Mr. Ming review their advantages and disadvantages. Mr. Zacher suggested that this light analytical treatment violated the Board's order issued at the pre-hearing conference. The Board is not persuaded that in omitting the 2034 modeling NB Power violated its order. While it would have been preferable to have had the 2034 modeling, NB Power did file Elenchus models of the Seasonal Sensitivities for Fiscal Year 2024 using the current and proposed rate classes. Mr. Ming and Mr. Knecht testified that the current cost drivers for NB Power's system will persist for the foreseeable future before significant wind penetration and other transformational changes materially alter the relationship between loads and costs in the next decade. This evidence, together with the nature of the Seasonal Sensitivities as alternative versions of the Average and Peak methodology, provides sufficient evidentiary basis for the Board to evaluate the Seasonal Sensitivities against the criteria established in Section 4, above.

[27] In response to NB Power's evidence, JDI filed Mr. Bowman's proposal for what it characterized as modest changes to the Average and Peak method. NB Power and Utilities Municipal objected to any consideration of the Bowman proposal on grounds that it was not properly filed under the agreement reached at the pre-hearing conference. The Board finds JDI properly filed Mr. Bowman's proposal as intervener evidence in response to NB Power's evidence-in-chief. That said, Mr. Bowman's proposals go beyond modest changes. In addition to a proposed four-period allocation for variable costs, Mr.

Bowman recommended changes to the classification of purchased power costs and export margin, and to the allocation of fixed costs. He did not model his proposal and offered multiple options for some of its elements, leaving the Board and the other parties with insufficient evidence to evaluate how the proposal would operate or make conclusions as to whether it would reasonably represent cost causation. The Board does not agree with Mr. Zacher's contention that NB Power was obligated to generate this evidence, as it was outside the original scope of this proceeding.

### 5.2 Average and Peak is not the most reasonable and equitable methodology

[28] The Average and Peak methodology does not better represent cost causation than a methodology that explicitly accounts for seasonal differences in energy costs. The present Average and Peak methodology ignores the manifest seasonal generation cost differences that the Seasonal Sensitivities recognize. Further, the evidence does not demonstrate that the Average and Peak methodology is the "most reasonable" option or is more equitable than the Seasonal Sensitivities that recognize these cost differences.

[29] Seasonal cost differences are real and the failure of the Average and Peak methodology to reflect them is a known and significant deficiency of the methodology. The Average and Peak methodology allocates demand-classified fixed costs using class contributions to the system peak which, in NB Power's case, always occurs during the winter season. The methodology does not account for time-based differences in energy-classified generation costs. Mr. Ming identified this deficiency as the "limitation" of the Average and Peak methodology. He noted in his report that customer classes with peaky load shapes drive generation costs due not only to their capacity needs, but also the energy they consume during hours when generation is expensive. In his view, the assumption that energy costs are unchanging throughout the year contributes to a relatively low allocation of energy costs to Residential customers, despite their high usage during high energy marginal cost hours. Mr. Bowman offered a similar opinion in his report. He used evidence prepared by Elenchus and filed with the Board in a previous proceeding to illustrate that the periods of highest variable energy cost coincide with load from classes that disproportionately consume energy in winter. Mr. Bowman concluded that the Average and Peak methodology materially under-allocates costs to those customers.

[30] These opinions went unchallenged and are consistent with the Board's decision in Matter 271, in which it approved NB Power's CCAS using the Average and Peak methodology. The Board noted that seasonal allocation of energy costs is a generally accepted approach and directed NB Power to file a strategy to introduce seasonal allocation of energy and demand generation costs together with a corresponding rate design strategy.

[31] Mr. Furey contended that the relative stability of revenue-cost ratios observed in the evidence across methodologies implies that the Average and Peak methodology is the most reasonable option. The Board does not agree.

[32] Mr. Furey relied on Ms. Zarnett's opinion that the hourly methodologies are not materially different from the Average and Peak methodology. After dismissing the Marginal Cost methodology for other reasons, Ms. Zarnett analyzed the Average and Peak with Time of Use and Probability of Dispatch methodologies and found that the revenue-cost ratios for all classes move no more than 3% in the same direction for both methodologies compared to the Average and Peak methodology. She also found that neither methodology would produce revenue-cost ratios that move into or out of the 95% to 105% range of reasonableness that the Board has previously determined to be equitable.

[33] The Board accepts the results of Ms. Zarnett's analysis of the proposed new rate classes, but not the conclusions Mr. Furey has drawn from them. Ms. Zarnett's analysis does not demonstrate that the Average and Peak methodology is the most reasonable option compared to the Seasonal Sensitivities. In fact, the evidence summarized in Appendix A to Mr. Furey's written submission undermines his conclusion. First, it shows that the Fiscal Year 2024 revenue-cost ratio for the current Large Industrial class exceeds Ms. Zarnett's materiality threshold when Average and Peak is compared to Probability of Dispatch. Second, while Ms. Zarnett did not analyze the Seasonal Sensitivities, Mr. Furey's submission that Appendix A shows no revenue-cost ratio differences greater than 2% between the Average and Peak methodology and the Seasonal Sensitivities also applies in reverse.

[34] Mr. Furey correctly cautioned against making changes to any aspect of the methodology without considering how the change might require changes to other components. The Board has taken this into consideration and as explained below, concludes that there is no evidentiary basis for making other adjustments to the classification or allocation of fixed costs to ensure that the Seasonal Sensitivities are equitable.

[35] The Seasonal Sensitivities are variations of the Average and Peak methodology that were developed by Elenchus on behalf of NB Power and filed with the Board in previous matters. The difference between the basic Average and Peak methodology and the Seasonal Sensitivities lies in their respective allocation of energy costs. The Main Seasonal Sensitivity allocates fixed and variable energy costs by seasonal average demand instead of annual average demand, while the Alternative #1 Seasonal Sensitivity allocates only variable energy costs by seasonal average demand.

[36] Mr. Furey maintained that the selective alteration of the Average and Peak methodology as contemplated by either of the Seasonal Sensitivities would "not [be] the most reasonable reflection" of cost causation. In his view, alternative methodologies must be assessed on a "holistic basis" to ensure the Board considers all aspects of cost causality instead of individual aspects in isolation. Referring to Mr. Knecht's evidence of the inverse relationship between fixed costs and variable costs, Mr. Furey asserted that seasonally allocating variable energy costs without simultaneously adjusting the allocation of fixed costs would introduce inequity in cost allocation. He referred to the Point Lepreau Nuclear Generating Station as an example of how very high capital costs may be offset by resulting lower fuel costs. Ms. Stevensen expressed similar concerns in the context of the Average and Peak with Time of Use methodology and Mr. Bowman's proposed four-period time step for variable energy costs.

[37] Mr. Knecht's evidence does not support the conclusion that any increase in temporal allocation of variable energy costs compared to NB Power's current model requires a decrease in cost allocated to peak demand.

[38] Mr. Knecht used what he referred to as the Turvey hypothesis to describe the tradeoff between fuel and capital generation costs. This theoretical construct places cost allocation methodologies between two extremes: one, a methodology that assumes one kind of generation with all fixed costs allocated to peak demand and all variable costs classified as energy; and, the other, the Turvey model where variable charges are priced at the highest variable cost of the highest peaking unit and capacity is priced at the cost of the lowest peaking unit. After describing this theoretical model in detail, Mr. Knecht concluded in his written report that the Turvey model "would imply using a much higher level of temporal variability in variable costs and likely a much lower reliance on coincident peak demand" compared to NB Power's existing approach.

[39] Mr. Knecht addressed this excerpt from his written report in response to an interrogatory from NB Power. He clarified that the statement was made in the context of moving from the Average and Peak model toward the theoretical Turvey model and stated it can reasonably be concluded that, at some point in increasing the temporal reflection of variable costs, the magnitude of costs related to peak demands should be reduced. In oral testimony, he described this as a "balancing effect" by which, as more and more variable costs are related to peak periods, the capital costs should go down. When asked by Mr. Furey about the evidentiary basis for his conclusions, Mr. Knecht pointed to the analysis in Mr. Ming's report showing lower fixed costs (17%) for the Marginal Cost methodology than for the Average and Peak with Time of Use methodology (27%).

[40] The Board is not persuaded by Mr. Furey's submissions that this apparent trendline indicates that any increase in time-based allocation of variable costs necessarily requires lower fixed costs. When Mr. Furey asked if it was his opinion that if the Board were to conclude that there should be a temporal reflection of variable fuel costs, then the magnitude of costs allocated or classified to peak demand should be reduced, Mr. Knecht responded, "No". The Average and Peak methodology is situated somewhere between Mr. Knecht's theoretical extremes and, in his submissions, Mr. Furey agreed with Mr. Knecht's opinion that there is no objective standard of perfection in cost allocation and no way to determine superiority among load factor methodologies. Further, Mr. Knecht elaborated on this point by saying that as methodologies are transitioning between his two theoretical extremes, it is not clear what that transition should look like. He also pointed out that the Average and Peak methodology lowers the percentage of fixed costs relative to his fixed/variable extreme from 100% to roughly 47%, without any corresponding adjustment in the variability of the fuel costs. Importantly, he said it is "not obviously better in any theoretical way than a load factor weighting with say, seasonal costs".

[41] Even assuming the Average and Peak methodology optimally represents cost allocation for NB Power's system, the evidence reviewed in paragraph [33] shows that the difference between the revenue-cost ratio impacts of adopting the Seasonal Sensitivities falls within the limits of what Mr. Furey conceded was equitable.

### 5.3 Further deferral of seasonal cost allocation is not warranted

[42] NB Power has expressed concern that seasonal cost allocation without the introduction of seasonal rates may mislead customers by giving price signals that ignore seasonal cost differences.

[43] The Board has in the past allowed NB Power to defer seasonal cost allocation pending the introduction of seasonal rates. Elenchus continues to hold the view that introducing a seasonal cost allocation methodology without a corresponding rate design raises equity considerations. Mr. Todd elaborated in his oral testimony that a corresponding rate design would provide the signal required to make customers aware they are paying a higher seasonal price and to respond by reducing their winter energy use.

[44] This consideration does not warrant further delays in the context of the ongoing rate design proceedings that prompted this review. To the extent that customers are currently receiving inaccurate price signals because of the lack of seasonal rates, seasonal cost allocation itself will not exacerbate that problem. As Mr. Todd pointed out in his oral testimony, the Average and Peak methodology already obscures the seasonal element

embedded in demand-classified generation costs under the Average and Peak methodology. The Board is also persuaded by Mr. Knecht's testimony that this concern is really a process issue that has hindered the implementation of seasonal cost allocation and seasonal rates over the eight years that have elapsed since Matter 271. Mr. Knecht testified that preventing the adoption of seasonal cost allocation without seasonal rates and vice versa confounds the Board's ability to make any change because cost allocation is often handled separately from rate design.

### 5.4 The Board selects the Alternative #1 Sensitivity

[45] Unfortunately, the Board did not have the benefit of the Public Intervener's views as to which option, if any, would be in the public interest because he made no representations in support of or opposition to any of the methodologies under review. Mr. Chiasson cited the statutory prohibition against the Public Intervener representing the interests of any particular customer class. He took the position that because modifying the CCAS would shift costs among rate classes, his hands were tied. With respect, the Board does not share this opinion. Rate regulation decisions by their nature almost always involve making choices that impact different customer classes and other stakeholders in different ways. In the Board's view, the Public Intervener has the statutory authority and duty to advocate for any specific regulatory outcome that, in his view, is in the public interest. That said, the Board acknowledges that the Public Intervener will interpret his enabling statute for himself as part of his obligation to make those representations that he considers to be in the public interest.

[46] The Board concludes that the Average and Peak methodology and its Seasonal Sensitivities are reasonably consistent with the regulatory principle that each class of customer should pay its fair share of the cost of service, but only the Seasonal Sensitivities recognize time-of-use-related energy cost differences caused by different customer classes.

[47] All three options can be reliably modeled using NB Power's present modeling system and are reasonably transparent and easy to implement. The Main Seasonal Sensitivity would assign fixed energy costs to a season by plant volume before allocating those costs by seasonal average demand. This step appears to add complexity and, perhaps, reduce transparency compared to the allocation of variable energy costs in both Seasonal Sensitivities. For that reason, the Board prefers the Alternative #1 Seasonal Sensitivity.

[48] The Alternative #1 Seasonal Sensitivity best meets the criteria established in Section 4. It reasonably represents cost causation by introducing time-based energy cost differences into NB Power's CCAS and is not inequitable.

[49] The Board directs NB Power to modify the classification and allocation of generation costs in its class cost allocation methodology in accordance with the Alternative #1 Seasonal Sensitivity and to use the resulting model to develop evidence of revenue-cost ratios beginning with the next general rate application.

## 6 Next Steps

[50] This proceeding is one step in the broader objective of designing a modern rate structure for NB Power that aligns with the Board's rate design goals, one of which is to reduce any inequity that may exist or may be caused by the current rate structure. With this ultimate objective in mind, the Board intends to continue examining potential opportunities to improve NB Power's CCAS as the larger rate design proceedings progress.

[51] The expert opinion evidence in this proceeding generated several potential CCAS modifications that warrant further examination.

### 6.1 Four-step temporal variable energy cost allocation

[52] Mr. Bowman recommended that NB Power segregate its variable energy costs into four time periods: summer, winter, on peak, and off peak. In his view, this approach appears to offer a practical means for achieving between 82% and 98% of the benefits of an hourly variable cost allocation without the need for creating a comprehensive hourly load forecast and cost data. Ms. Stevensen cautioned that implementing Mr. Bowman's proposal may require the same hourly data that presently makes other hourly methodologies unavailable, though Mr. Bowman believes it can be implemented using PROMOD.

[53] As discussed in paragraph [27] above, Mr. Bowman's proposal has not been sufficiently modelled to be considered for approval in this proceeding. However, the Board sees merit in evaluating Mr. Bowman's recommendation as a potential option for future consideration among other time-based methodologies.

### 6.2 Coincident peak allocator

[54] Mr. Bowman proposed modifying the allocation of fixed demand-classified generation costs in the CCAS by replacing the current allocator with a coincident peak allocator derived from a single forecast extreme peak using a P90 peak forecast value or one or more historical peak hours. P90 refers to the $90^{th}$ percentile, meaning a 10% probability that the forecast peak will be exceeded. He urged the Board to direct NB Power to develop a measure of the extreme peaks and the relative class contributions to those extreme peaks for the purposes of cost allocation, or alternatively to look to planning

peaks going forward at the P90 level and develop reasonable estimates of the customer specific contributions towards those P90 peaks. In his view, asking the utility to determine how to better capture the cost drivers instead of specifically directing a particular measure is preferable because it avoids summary rejection of proposals because of current data availability challenges.

[55] The Board accepts Mr. Knecht's evidence that regulators are often hesitant to rely on a single coincident peak measure for allocating demand costs because of the potential for non-representative results, and that this is a more serious concern when considering actual historical peak demands instead of using a forecast system coincident peak.

[56] Ms. Stevensen cautioned that using a P90 peak forecast value would pose challenges for NB Power due to data availability issues and budget forecasting that is based on P50.

[57] The Board concludes that Mr. Bowman's proposal warrants further examination because the evidence no longer supports the Board's justification in Matter 271 for establishing the multiple coincident peak allocator. The Board stated in its Matter 271 decision that using a three coincident peak allocator where the demand peaks are within 10% of the single coincident peak is a recognized approach in the NARUC Manual and would likely provide a more reliable result. Mr. Bowman's analysis of data from Fiscal Years 2021 to 2023 demonstrates that one of the three winter months used to develop the 3CP allocator fell well below 10% of the peak in two of those years.

[58] The Board concludes that modifying the allocation of fixed generation costs in the class cost allocation model by replacing the current allocator as Mr. Bowman recommends may more reasonably reflect seasonal cost differences in demand-classified generation costs.

### 6.3 Classification of purchased power costs and export sales

[59] Mr. Bowman recommended classifying purchased power costs as demand-related or energy-related based on the system load factor. NB Power disagrees. Mr. Furey challenged the underlying assumption that power purchases are almost all long-term contracts requiring NB Power to take the entire output produced by the counterparty and the remaining few are "spot" transactions. He cautioned against implementing Mr. Bowman's proposed changes without assessing NB Power's supply mix of purchased power and no party opposed the idea that the terms of NB Power's power purchase agreements should inform the allocation of purchased power costs. The Board concludes that an assessment of NB Power's supply mix of purchased power is warranted.

[60] Mr. Bowman also recommended classifying out-of-province energy sales, other than capacity sales, as 100% energy-related instead of by system load factor. In his view, out-of-province capacity contracts classified as demand-related are improperly double-counted. NB Power opposed this recommendation on the basis that export revenues enabled by system assets should be treated in the same fashion as those assets. The Board finds no evidence of double counting. Further, Mr. Knecht's opinion aligns with NB Power's current approach, except with respect to market sales. Mr. Knecht recommended allocating market sales margins as miscellaneous revenue because market sales involve NB Power buying energy outside the province and selling it on the market without incurring system costs. The Board notes NB Power proposes to file evidence in the next rate application in support of Mr. Knecht's recommendation.

### 6.4 Directions for further analysis

[61] The Board intends to consider further class cost allocation methodological changes. To facilitate that process, the Board directs NB Power to take the following steps and file the results of its work in Phase 2b of the rate design proceeding, as defined in the Matter 529 Decision:

a. model the four-period allocation of variable costs proposed by Mr. Bowman using the same method as the Average and Peak with Time of Use model or a similar method, model any other multiple-period allocations of those costs the utility wishes the Board to consider and for which sufficient data is available, and, in each case, demonstrate how the model results compare to those of the Average and Peak with Time of Use model;

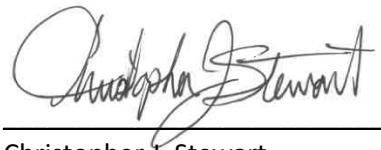
b. develop a proposal to modify the allocation of fixed generation costs in the class cost allocation model by replacing the current allocator with a coincident peak allocator derived from a single forecast extreme peak using a P50 peak forecast value or 10 historical peak hours; and

c. evaluate its purchased power agreements and supply mix and estimate what proportion of its purchased power costs provide a reliable implicit or explicit capacity benefit.

[62] The Board will also consider any other class cost allocation methodological changes that the utility wishes to propose as part of the Phase 2b rate design proceeding.

[63] The Board will not direct NB Power to implement seasonal rates at this time, as the potential exists for further adjustments as the rate design process continues.

Dated at Saint John, New Brunswick, this 2nd day of April, 2025.



Christopher J. Stewart
Chairperson

Heather Black
Member

Kenneth McCullogh, K.C.
Member