PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO MATTER 554
NEW BRUNSWICK POWER
CLASS COST ALLOCATION STUDY ("CCAS")
METHODOLOGY REVIEW

Submitted to:

The New Brunswick Energy and Utilities Board

on behalf of

J.D. Irving Limited

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1.0 INTRODUCTION

This Pre-filed Testimony has been prepared by Mr. Patrick Bowman of Bowman Economic Consulting Inc. for J.D. Irving Limited. This testimony reviews and assesses the New Brunswick Power ("NBP") Class Cost Allocation Study ("CCAS") methodology, as part of Matter 554 (the "Application") filed with the New Brunswick Energy and Utilities Board ("EUB") on December 15, 2023, and related materials.

With respect to the testimony contained herein, Mr. Bowman notes the following:

- Mr. Bowman is an independent witness and his Resume is provided in Appendix A.
- Mr. Bowman's scope on this assignment was to review and assess the Application taking into account relevant regulatory principles for electric cost allocation.
- Mr. Bowman acknowledges his role is to provide opinion evidence to the Board that is fair, objective and non-partisan.
- Mr. Bowman has endeavoured to ensure all factual assumptions and specific information relied upon are expressly cited in the testimony that follows.

This is the second NBP proceeding in which Mr. Bowman has participated. Mr. Bowman provided testimony in Matter 529 regarding rate and class design.

As set out in Appendix A, Mr. Bowman has been involved in electricity regulation and cost allocation matters since 1998, and has prepared expert evidence and testified on the subject on multiple occasions across numerous jurisdictions throughout Canada, particularly those with Crown-owned vertically integrated utilities. Mr. Bowman's cost allocation experience includes work for each of utilities, large industrial customers, small commercial and residential customers, and wholesale customers.

With respect to terminology, this evidence uses the term "method" to describe one analytical approach to addressing some aspect of CCAS calculations. The term "methodology" is used to describe a full set of methods needed to produce a CCAS, and the output of the CCAS process is described as a "model" (with "modelling" referring the process of producing a model).

1.1 SUMMARY OF CONCLUSIONS

Broadly, the NBP CCAS under the currently approved methods generally reflects industry standard CCAS approaches, with limited exceptions.

With respect to generation and power supply costs, the currently approved CCAS models the costs allocated to the various classes in a manner that fails to appropriately reflect causation associated with meeting the highest peak loads during cold winter periods, and fails to appropriately differentiate the cost drivers (causes) of energy costs as they vary across time periods. This leads to under-allocation of costs to customers who make greater use of power in peak periods, and in winter.

Outside of addressing these two broad weaknesses, the CCAS methodology would benefit from a number of small improvements to increase the quality of cost tracking.

Specific recommendation contained in this testimony are as follows:

Recommendation 1: Methodology updates to the CCAS should not be further delayed until more granular rate designs can be implemented. Previous proposed updated to CCAS have been delayed, and NBP and Elenchus appear to consider it appropriate to continue to delay implementation. This will not yield rates to the different classes that are just and reasonable. (section 2.3)

Recommendation 2: CCAS methods that minimize the need for confidential data inputs or methods should be preferred where possible, to facilitate implementation and permit transparent and public review in future GRAs. (section 3.0)

Recommendation 3: Continued use of the System Load Factor as the primary method to generation classification is justified based on energy and demand trends, and its use is well-supported among Canadian utilities. System Load Factor appropriately represents the mixed role of generating resources to meet both energy and demand requirements. (section 3.1)

Recommendation 4: NBP generation plant (nuclear, hydro, thermal), as well as power purchase costs (where not explicitly for export purposes), should be classified to demand and energy based on the System Load Factor. This change adds purchases to the method currently used for NBP owned assets. As power purchases, such as wind, become a more material part of the system and NBP's IRP planning, they should receive the same treatment as NBP owned resources, reflecting their role as part of a comprehensive generating resource portfolio. (section 3.1)

Recommendation 5: The calculation of the System Load Factor should be based on NBP sales exclusive of interruptible loads, except where such loads are included in system planning and the basis of capital investment. Interruptible sales that are not part of the loads considered for capital investment purposes should not be included in methods meant to classify the costs of those investments. (section 3.1)

Recommendation 6: NBP out of province sales should be classified to 100% demand when related to capacity sales, and to 100% energy for other sales. The current classification method (100% demand for capacity sales and System Load Factor for all others) over-emphasizes the demand contribution towards these sales. (section 3.1.1)

Recommendation 7: Use of a multiple coincident peak value for demand allocation (such as the current 3 CP) may be appropriate, but it should be based on the highest firm load hours of the year, regardless as to the month in which those hours occur, rather than the highest hour of each of December, January and February. It may also be reasonable to expand the set of hours to include those close to the peak (e.g., within 5-10%) which would be approximately the 10 highest hours in a year based on recent experience. (section 3.2.1)

Recommendation 8: Of the 3 novel CCAS methods analyzed by E3 (Loss of Load Probability, Probability of Dispatch, and Marginal Costs), none of these methods are practically viable or demonstrate any significant benefit for CCAS use on NBP's system. These methods are also largely unprecedented in Canadian CCAS practice, and each comes with extensive problems related to data availability, confidentiality and implementation in CCAS. None of the method should be adopted by NBP. (section 3.2.1)

Recommendation 9: For the purposes of Coincident Peak allocation in the CCAS, the peak load responsibility should be based off the risk or weather-adjusted load forecast, such as at the P90 level, rather than the P50 level. Serving the highest peaks that arise – which are above the expected (P50) level, are a key cost driver to investment. Allocation of costs should reflect the classes which impose this cost on the system. (section 3.2.2)

Recommendation 10: Energy cost allocation for NBP should include consideration of the differing incremental cost of energy production in different time periods, rather than an oversimplification based on averages at the level of annual usage. Annual average usage poorly tracks the pattern of energy costs as they vary across the day and year. (section 3.2.3)

Recommendation 11: The most accurate method for allocating energy-related variable costs, including power purchases, is the hourly time-step TOU method. Other methods for energy-allocation other than TOU may be suitable, in the event they are more practical, so long as they closely mimic the results from the hourly TOU method. (section 3.2.3)

Recommendation 12: Use of a 4-period time step for energy allocation (winter/non-winter, on-peak/off-peak) appears to permit most of the benefits of the hourly TOU method to be achieved at a far less data intensive scale. However, if this method does not ultimately yield the majority of the accuracy benefits of the more granular hourly TOU method, with a simpler and less data-intensive model, the TOU based allocation of variable energy costs should be adopted. (section 3.2.3)

2.0 CLASS COST ALLOCATION BACKGROUND

2.1 BACKGROUND – CCAS THEORY

Cost allocation in utility ratemaking is an intermediate step between establishing the overall level of dollars to be collected (Revenue Requirement) and the setting of the particular rates (both form and quantum) to be charged to customers (Rate Design). Cost allocation a distinct step in the ratemaking process, informed by, but independent from, the other two steps.

The particular importance of cost allocation is to achieve fairness among the different classes of customers. This is consistent with the principles of the New Brunswick *Electricity Act* section 103, which focuses on "just and reasonable" rates.

- Cost allocation is unique from the **Revenue Requirement** setting step, which is to achieve balance and fairness between customers and the utility – recovery of all just and reasonable costs and prudent investments, and provision of a fair financial outcome for the utility.
- Similarly, the cost allocation step's focus on fairness among and between the customer classes is different than the **Rate Design** stage, where the objective is to achieve efficiency, send appropriate rate signals regarding usage and conservation, and, in part, to achieve fairness within each class. Limitations on the availability of rate designs to achieve efficiency or fairness within a class should not be a limit on the separate objective to achieve fairness among the classes.

CCAS is an analytical tool. It is not a measure of precisely what, or in what manner, customers will pay for power. CCAS should provide an accurate measure of the costs caused by each class. Once this analysis is conducted in a reasonable manner, the regulatory process can turn to determining what revenue will be collected from each class (including determining how closely rate revenues will adhere to costs – known as the Revenue to Cost Ratio, or "RCR") as well as how to design rates taking into account multiple factors, commonly known as the Bonbright principles, including considerations such as stability of rates and efficiency of price signals.

Cost causation is appropriately the basis for cost allocation, and the valid end goal of a CCAS analysis. Allocation of costs to each class can only be determined to be just and reasonable to the extent that the allocation reflects the costs caused by the class. NBP has similarly described that, in the case of New Brunswick, "(t)he CCAS methodology is based on cost causation principles."[1]

[1] Ex. NBP 2.01, pg. 1.

Cost causation is, at its core, about which customer use in the Test Year is driving the need to incur costs, or to make or to maintain an investment, as outlined by Elenchus[2]:

> The term "causality" in cost allocation typically refers to the customer class that is driving the current need for the asset. For example, the current capacity of the system that is needed to serve the current customer classes at any point in time (causality) is based on the total demand that is attributable to the relevant classes. Hence, it is current demand that is deemed to "cause" the capacity-related costs.

Not all customer uses drive all costs. For example, with respect to a common asset such as a utility meter, within reason it does not matter whether a smaller customer uses considerable energy or very little, there nonetheless remains a need for one meter to serve the customer[3]. In this example, energy consumption is not a driver or "cause" of the meter – the presence of the customer is the cause. Therefore, meters are classically one type of cost that is classified as "customer-related" (rather than "energy-related"). This example illustrates the important distinction between *cause* versus *use*. At various places in NBP's evidence there is discussion about how any individual asset is *used* (or has a probability of use). This focus on use can lead to incorrect allocation conclusions. A residential meter is *used* to measure each kW.h of energy delivered. Every kW.h spins the meter and as such is recorded for the purposes of billing. If the question is solely one of use, a meter may be considered an energy-related asset. However, this is an incorrect conclusion, and meters are almost universally classified as customer-related, not energy-related[4]. While the meter is *used* by each unit of energy, the investment in the meter is not *caused* by the energy use – it is caused by the presence of the customer.

Similarly, once a network transmission system has been designed to deliver all required supply (MW, or capacity, or demand) reliably at the highest peak hour of the year, there is typically no further transmission network cost driven or caused by customers adding to peak loads at low load times. The driver of the scale of the investment is the peak load imposed on the system, not use of the system off-peak. This type of peak load cost classification is used for "demand-related" costs (including for NBP transmission).

Mixed purpose assets, such as hydraulic plants, can be both energy-related and demand-related, and the division of costs between these two categories (the step known as "Classification") will commonly be based on the loads that these plants must serve, as based on the system load factor ("SLF").

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[2] Ex. NBP 7.03, pg. 43, response to JDI IR-13(i)

[3] Larger customers can have more complicated meters customized to their service, which are directly allocated to their class.

[4] Ex. NBP 7.07. Response to NBEUB IR-4; NARUC manual on Cost Allocation, page 91 and 100. The exception is when meters are weighted by demand to reflect that some large customers have more expensive meters, which is a rare approach.

A further relevant concept of is that of historical purpose. Elenchus correctly notes that the reason an asset was originally built is rarely the basis for cost allocation today[5]. However, there remains a distinction between the way an asset is used today, and the main planning purpose on which the asset continues to be justified. For example, a party may employ the term *use* to refer only to an asset being dispatched; however, there may well be assets that are never used in this sense (for example, last-resort generation options). Similarly, an asset may be routinely used for incidental low value purposes, though its main planning purpose is for reliability service at peak times – absent this planning purpose the asset would never have been built, nor would its cost continue to be justified. An example may be a low efficiency thermal generating unit which is justified and maintained due to a critical role as last resort backup generation for peak times. This unit may be occasionally dispatched if marginally *in the money* if economic for export (i.e., it yields an incremental net positive revenue above incremental costs), to earn a marginally (but still positive) return. However, although this is rational behavior that should be pursued by a utility, the asset was never built, nor maintained in service, for that low-margin purpose, and the cost of the asset should not be allocated in a manner that over-recognizes this low value *use* which is not the cause of the investment. The export transaction is incidental – it is not a cause of investment. This issue underlines a foundational problem with the entire "Probability of Dispatch" concept that NBP has explored, as discussed in later sections of this evidence.

2.2 SUMMARY OF NBP'S SUBMISSION

NBP has provided a submission that provides a CCAS model based on NBP's existing approved methodology[6], a model that updates the CCAS using largely status quo approved methods but based on detailed updated load analysis by E3 consultants[7], and three alternative methodologies that have not previously been considered for NBP's system.

NBP also presents two seasonal methodologies that have previously been considered in Matter 357 (another two methodologies from Matter 357 were not updated and NBP has rejected updating those models[8]). The output of the seasonal models are not presented in NBP's summary tables of the options for this proceeding.[9]

The methodologies all relate solely to the generation function, which includes cost allocation of assets and costs for NBP owned assets, costs for power purchases (both in-province and out-of-province), and the allocation of revenues from out-of-province sales.

[5] Ex. NBP 7.03. Response to JDI IR-14(e)(i).
[6] Ex. NBP 2.03; 5.05
[7] Ex. NBP 2.09; 5.06; 7.08
[8] Ex. NBP 7.01, page 17. Response to NBEUB IR-9(c).
[9] Ex. NBP 2.01, pages 9-10.

Costs functionalized as transmission and distribution are excluded from the review.

The methodologies modelled by NBP are generally applied to the 2023/24 test year using the existing class structure. As well, some of the methodologies are modelled for some or all of the following conditions:

- A projected 2033/34 test year.
- New customer classes arising from Matter 529, which are to be in place within the next few years
- A possible subdivision of the new Large Transmission class, to create a subclass for those customers who peak at less than 25 MW, versus those that peak above 25 MW

Among the range of methods modelled, it is important to recognize that the specific output from the various CCAS models cannot always be meaningfully compared on an apples-to-apples basis. This is because there are variations in the input data that limit comparability. Meaningful comparison of results can only be achieved in cases where the basic input values are the same. The variation in input values arise due to the following variations:

1) The original 2023/24 CCAS data for export sales and out of province revenues reflect an error in the matching of some export transactions (costs versus revenues are mismatched). This was addressed in concurrent Matter 552[10]. A number of the original models provided in this filing fail to correct the error, though they have been replaced by later versions that do make the necessary corrections.
2) Through detailed analysis of load by NBP's consultants E3, the base input data for usage by customer class has been adjusted. The E3 loads are not complete – for example, LIREPP loads are not included in the output, the E3 loads reflect an erroneous allocation to the hypothetical new Industrial 25MW class even when this class is not being modelled[11], and the load forecast used to prepare the E3 analysis predates the final decision model load data from 2023/24.[12] Both versions of the loads are used at various times in the filing.
3) A number of the models use an initial classification step to divide generation cost between energy and demand (some methodologies do not require this classification step[13]), and all use the traditional concept of a load factor to make this classification. However, the use of E3's modelled data resulted in a change to the load factor used to classify generation costs to demand and energy. This change is included in some CCAS models but not in others.

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[10] Ex. NBP 10.05, page 77.
[11] Ex. NBP 7.03, page 13, footnote 1.
[12] Ex. NBP 7.03, page 14. Response to JDI IR-5(b) parts (iii) and (iv).
[13] Specifically, this applies to the Marginal Cost approach, and the Probability of Dispatch approach.

This is simply a caution in interpreting model results (e.g., RCRs). Comparison between the results of various models requires that the models are prepared with the same input conditions and assumptions for the above factors.

2.3 ELENCHUS' OPTIONS ASSESSMENT FRAMEWORK

Elenchus was retained by NBP to conduct the analytical CCAS modelling for this proceeding.[14]

NBP also provided a subsequent assessment from Elenchus dated February 20, 2024, setting out the merits of the various methods.[15] Elenchus presents their assessment of the methods as being dependent on a preliminary "policy decision" regarding which of Elenchus' conceptual frameworks should be adopted:

- the Generation Black Box ("GBB"), where generation is analyzed without reference to the individual characteristics of the generation supply mix.
- The Fully Transparent Box ("FTB"), where generation is analyzed based on "actual operating characteristics of the utility's supply resources on a highly granular basis (e.g., hourly)"[16]

A number of issues arise from the Elenchus use of these concepts.

First, the GBB and FTB nomenclature and concepts are, to my knowledge, unprecedented and do not arise from any literature on cost allocation[17]. Indeed, no known cost of service method references these terms, and Elenchus could not provide any specific reference for the use of these terms.[18]

Second, the concepts are premised on two extremes – a near-complete ignorance of the loads that must be served by generation (GBB) or a high granularity of the generating complement and loads which Elenchus insists must be at the level of hourly operating data (FTB) applied to demand and energy. Elenchus does not address why the methodologies must be assessed by reference to making a binary choice between these two extremes, particularly in light of the fact that the EUB has already previously arrived at a conclusion that "(t)he seasonal allocation of costs, including energy costs, is a generally accepted approach" and that it "adds precision" and "there is value in considering this methodology."[19]

A final issue with the Elenchus analysis is that Elenchus has itself produced options for cost allocation on a basis that is more granular than the status quo since Matter 271 (2016); for example, seasonal or monthly allocations. However, Elenchus has rejected implementation of these methods based on Elenchus' view

[14] Ex. NBP 7.03, page 4, JDI IR-2(a).
[15] Ex. NBP 4.01.
[16] Ex. NBP 4.01, page 3.
[17] Ex. NBP 7.03, pages 38-39. JDI IR-13(b).
[18] Ex. NBP 7.03, page 39. JDI IR-13(c).
[19] Board Decision on Matter 271, paragraph 84.

that improved cost allocation (i.e., fairer treatment among the classes) should not be considered until a more refined rate design (i.e., better price signals within each class such as Time of Use pricing) can concurrently be adopted. Specifically, Elenchus notes[20]:

> Elenchus clearly stated its view in its 2017 Report, a view that it continues to hold today, that the introduction of a cost allocation methodology that relies on seasonal demands (or time varying demands over any other time frame) without also adopting a corresponding time varying rate design would raise important implications in terms of the equity principle for ratemaking.

In short, it appears Elenchus has set out a position that the "policy decision" between GBB and FTB is both an essential first step, but also in some respects is a false choice, since FTB can never be implemented. There is no prospect of NBP developing hourly FTB rates for customers, and any attempt to do so would be likely prohibitively complicated, as well as unprecedented.

The fundamental issue with the Elenchus position, and proposed delay in implementation, is that it ignores the issue of fairness among customer classes. Elenchus does not provide any reason why, in the absence of a refined residential or small business rate design (for example), costs that are driven by, and therefore properly allocated to, the residential or small business classes, for example, should instead be allocated to other classes, thereby ignoring merited improvements to CCAS. Indeed, with the ongoing priority to electrify and to expand heat pump usage, it is conceivable that seasonal or more granular residential or small business pricing may never be consistent with the broad policy objectives for rates. Undermining a valid utility objective of fair cost allocation among classes pending resolution of the separate topic of rate design is not consistent with good utility rate practice in producing an analytically accurate CCAS, nor with providing the needed inputs to support the development of just and reasonable rates.

> **Recommendation 1: Methodology updates to the CCAS should not be further delayed until more granular rate designs can be implemented.**

2.4 KEY ASPECTS OF NBP SYSTEM PLANNING

CCAS should reflect the allocation of embedded costs (as reflected in the Revenue Requirement) across the loads to be served in the Test Year. However, as methodology updates are only done periodically, the methodology should generally be durable over at least the expected and pending system conditions, constraints, and cost pressures that will be faced in coming years, and until a future CCAS review.

[20] Ex. NBP 7.03, page 38; JDI IR-13.

NBP has indicated that system planning at present and for future periods will be driven by a number of key factors, notably:

- The requirement to decarbonize electricity generation.
- Expected increases in renewable supplies, particularly wind, provided by third-party power producers, represented as purchases in the future CCAS. This will also drive challenges meeting peak supply requirements, as wind is not dispatchable.
- Growth in winter loads as more of the province's heating requirements are met by electricity (including heat pumps). This will also drive the sensitivity of system peak to extreme weather conditions.

NB Power emphasizes the challenges in the Decarbonization Strategy, citing one of the "key findings" as follows[21]:

> To ensure reliability as peak load grows, the system requires increasing quantities of firm generating capacity. To provide winter reliability, the system requires new capacity to meet the system's reliability standard (modeled as one-day-in-ten-years). Wind and battery storage can meet a portion of this need but are subject to diminishing marginal returns as more of these resources are added. As much as 2.2 GW of total natural gas capacity may be needed to replace retiring capacity and meet load growth. These resources are operated less and less over time as more clean energy is added but are vital for ensuring reliability during <u>extreme weather events</u>. (emphasis added)

Or, more succinctly, NBP notes:[22]

> The nature of the reliability challenge in New Brunswick is meeting cold winter peaks.

As noted in the above quotes, it is meeting peak load requirements, driven by weather events, that drive material ongoing consideration and investment in generation planning. This factor is of key concern today and there is no indication that the importance of this will change over time – if anything, with increasing non-dispatchable resources and electrification, the challenge of meeting the coldest winter peaks will grow. Appropriate CCAS consideration of this factor would ensure that peak load drivers, and in particular those that are weather dependent, are properly allocated a material share of system costs.

[21] NBP (NBEUB) IR-01 Attachment E3 New Brunswick Decarbonization Strategy Study Executive Summary Decarbonizing Electricity Generation in New Brunswick Decarbonizing Electricity Generation in New Brunswick
[22] Ex. NBP 7.05 Decarbonizing Electricity Generation in New Brunswick, page 26.

At the same time, NBP is planning to add material wind resources to the system. This will drive two key changes to the CCAS inputs:

1) **Purchases are not incidental:** In the past, it appears NBP system energy purchases were smaller volume, and would generally not have been considered to be a core component of system planning in a manner that drove the investment in utility generation plant. This type of purchase is often considered to largely displace fuel costs associated with energy generation, or to fill energy supply needs during schedule maintenance periods. Either way, this type of energy supply does not generally change the scale or type of generating units that must be installed by the utility. This pattern will change in future, as purchases from independent producers of renewables grow. System purchases will no longer be incidental or convenience resources, and will become a more substantial portion of the overall revenue requirement. The new IRP is integrally linked to these purchases, and the type and size of generation NBP must maintain will be materially influenced by the characteristics of these purchases.

2) **Integrated generation plant:** As non-dispatchable resources grow in volume, resources that can provide stable base load generation – or, of even more value, variable dispatchable generation – become a larger factor in meeting overall peak loads. Increasing amounts of wind will provide significant energy, but little capacity. As a result, the role and importance of nuclear, hydro and thermal resources to provide reliable firm capacity, or peaking capacity, will be of increasing value. This underlines the importance of integrated system cost classification – though costs may be added for wind, which is primarily energy, it does not change or undermine the principle of a consolidated SLF analysis being used to classify the entire generating complement that is comprised of hydro, nuclear, thermal assets, and wind. While the wind component may be more energy skewed, the other assets work together with the wind to meet a load profile that can be properly represented by the overall SLF.

3.0 CCAS METHODS

The conduct of a CCAS requires three main steps – Functionalization, Classification and Allocation. In this case, the review is focused on only the generation function, so the Functionalization step is not at issue.

Classification is the division of costs into the different services they provide – demand (or peak, or capacity) and energy (sometimes referred to as "average demand"). Allocation addresses how costs classified in this manner are allocated to the various classes. The end result of the Allocation stage is a total cost for which each class is responsible. The design of rates to recover that cost occurs outside CCAS and is not a factor in determining the CCAS outcomes, and is not further addressed in this testimony.

The remainder of this section addresses Classification and Allocation.

Each step of the Classification and Allocation assessments focuses on the basic cost concepts of Capacity/Demand/Peak versus Energy. These concepts are typically applied to generation and consumption in combination – that is they are concurrently being supplied and can appear difficult to differentiate. However, in terms of costing, each of energy and capacity (demand) have an important meaning and contribution.

- Capacity is the ability of a system to meet peak demands reliably at the moment demanded by customers. As a pure concept, capacity is a key utility planning constraint that represents costs incurred to meet the time demands of customers, but only for a limited time (e.g., the highest usage moment in a year). A utility will undertake investment decisions to meet the anticipated future customer peak demands, with a reserve operating margin added for contingencies (such as for peak usage above the normal forecast, such as the occurrence in early February 2023 during the 'polar vortex' that drove peak electricity usage levels in that year).
- Energy is a concept that is unlinked from time – delivery of the service that lets work (in the scientific definition) be performed. Energy is the ability to do work and is unrelated to the time it is delivered (in the abstract – an energy product is a Joule delivered at any time in the year without a customer's ability specify when it will be delivered[23]). In this way, the purest concept of energy is not a particularly useful concept as there is almost no commercial nor utility planning concept that entirely delinks the delivery of the ability to do work from the time in which the

[23] A watt is a joule per second, or work divided by time. The classic unit of energy – kilowatt-hour – is work divided by time multiplied by time – and thus is simply a unit of work divorced from time.

delivery occurs[24]. In practice, energy does require consideration of the time in which the energy is delivered, in a manner that is different than the acute time constraints related to meeting a utility's highest peak demands.

This section assesses CCAS methods with a focus on both accuracy and practicality. It is important that a CCAS be accurate in representing the reasons a utility makes investments or incurs costs, typically tied to the Test Year in which the CCAS will be used. However, it is also important to be attentive to practicality. A CCAS should preferably not require creation of large amounts of data where this data is not otherwise used by the utility in a rate proceeding. The CCAS should also not require large amounts of data that cannot be readily and publicly tested, to a reasonable extent. This proceeding has permitted a degree of information sharing of confidential data that is understood will be unavailable to parties in future GRAs when the CCAS methods will be applied. If such data requirements are in fact integral to the methodologies, then such informational challenges will need to be addressed. If these data confidentiality issues cannot be resolved, then the methodologies are likely ill-suited to a CCAS, which is meant to help convey fairness to all customers classes.

Recommendation 2: CCAS methods that minimize the need for confidential data inputs or methods should be preferred where possible, to facilitate implementation and permit transparent and public review in future GRAs.

3.1 CLASSIFICATION

The classification of system generation costs into demand and energy occurs as the second step in CCAS, after Functionalization.

The current system classifies most NBP generation costs based on the SLF. According to the latest Decision Model (the final approved output of the previous GRA), the SLF is approximately 50% based on a 3 CP peak value.[25] This means that 50% of the costs classified based on the SLF will be recovered as energy costs and 50% as demand costs.

[24] In the most extreme cases, utilities dominated by hydro generation (e.g., Manitoba Hydro) can require assessment of whether the utility can meet energy requirements in their purest form, because it is possible that during a drought, a paucity of water (i.e.., fuel) may mean that the load can be met in any given hour, but not sustained to be met over the course of a year. This is not a typical constraint for most utilities using blended supply sources.
[25] Ex. NBP 5.05, Add VII. Note that Ex. 2.52 from Proceeding 552 shows this value remaining at approximately 51:49 (energy:demand) for 2025/26, per Add VII.

Under the approved methodology, all costs of nuclear[26], hydro and thermal investment are classified on the SLF basis[27]. This includes amortization expense, interest and net income expense. Production O&M is similarly classified on the basis of SLF, as is System-related Energy Efficiency.

Production fuel is classified 100% to energy, as is purchased power.[28] The exception is fuel and purchased power that is explicitly used to service exports[29], and fuel used to service interruptible or surplus sales, which are directly assigned as a cost against those sales.[30]

Elenchus provides a memo that sets out the CCAS methodologies used by seven peer utilities. Elenchus, however, does not consider two peers that are of relevance, Newfoundland Hydro ("NLH") and FortisBC. These peers are relevant as they operate vertically integrated fully-regulated systems, like NBP. Looking to the classification of generation:

- Of the seven utilities surveyed by Elenchus, all but two use an SLF method for the majority of investment. The exceptions are Maritime Electric (which uses 100% demand for all generation except Point Lepreau at 25% demand) and Hydro Quebec (which uses a utilization factor during the peak 300 hours – which leads to 69.4% of plant being demand classified). In addition to broad use of SLF, a common supplemental method is to classify certain assets more to demand based on the peaking role these assets fulfill (e.g., Newfoundland Power non-hydro generation at 100% demand).[31]
- NLH also uses SLF for hydraulic assets and purchases, with a plant capacity factor for winter use thermal plant, which leads to higher demand classification than the SLF[32] and 100% demand for peaking thermal units.
- FortisBC uses classification based on the same ratio that they would pay to purchase the generation from BC Hydro (a significant part of FortisBC supply is not provided by utility owned assets, but by purchases from BC Hydro, so the BC Hydro cost profile is extended to the utility's own generation).[33]

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[26] This includes the PLNGS refurbishment deferral account balance, which is appropriately allocated consistent with the nuclear assets as it relates to costs incurred to make capital improvements or refurbishments. Ex. NBP 5.05, Add I.
[27] Ex. NBP 5.05 Sch 3.1, 3.2, 3.4.
[28] Ex. NBP 5.05 Sch. 3.3, 4.3.
[29] Ex. NBP 5.05, Sch 2.3 column 4.
[30] Ex. NBP 5.05, Input, cell D312.
[31] Manitoba Hydro is noted to use a 100% energy classification for wind, but as per Manitoba PUB Order 101/23, this item is subject to review following completion of Manitoba Hydro's current IRP and the receipt of information on the role of various generation in assisting in meeting capacity peaks. Manitoba PUB Order 101/23, page 168
[32] Newfoundland and Labrador Board of Commissioners of Public Utilities, Order P.U. 37(2019) Schedule A page 3 of 5 (pdf page 9 of 11)
[33] BCUC proceeding 1598939 FortisBC 2017 Cost of Service Analysis and Rate Design Application, Ex. B-1, pdf page 168-170 of 715. COSA Report, pages 28-30.

The peer review provides broad based support for continued use of SLF as an appropriate method of classification for NBP assets.

Further, the SLF represents a reasonable means of matching the generating complement to the loads that it must meet. The peakier the load (i.e., lower SLF), the less that the utility investment in generating plant is needed for energy purposes and the more it is for meeting capacity – the SLF method would naturally evolve to classify less of the costs to energy and more to demand in this situation to meet this change, and vice versa. As such, the SLF is a reasonable and elegant method, which underlines its merits and the reason for wide adoption.

> **Recommendation 3: Continued use of the System Load Factor as the primary method to generation classification is justified based on energy and demand trends, and its use is well-supported among Canadian utilities.**

The SLF classification is not at present used for purchases. At present, purchases are classified 100% to energy.[34] This 100% energy allocation method is sometimes used by utilities when the purchases are small, not directly impacting on the utility capital investment, and of little value or firmness to meeting system peaks, which is unlikely to fit with NBP's future evolution. For purchases that are integral to the system, a more common method is to classify the generation as if it was utility-owned plant.

Future evolution of the NBP system towards more purchases and non-utility generation (e.g., wind), with limited dispatch of NBP's thermal generating assets may indicate a need for increasing demand classification of these thermal assets, consistent with the other utilities noted (e.g., NLH 100% demand for peaking thermal units, and plant capacity for winter baseload thermal units; also Newfoundland Power 100% demand for non-hydro assets). Based on the growing importance and challenge of meeting peak demands on the NBP system, this method is more appropriate in order to properly recognize and allocate these costs to the classes that are driving peak loads. There are two broad ways to address this system transition:

- First, assets that play an increasingly valuable and focused role in meeting peak demands could be classified more to demand. This would be matched with classification of power purchases to demand and energy (e.g., wind) in a manner that recognizes their respective contribution to each service (demand versus energy) – e.g., Effective Load Carrying Capability ("ELCC"), a measure of their relative contributions to serving demand in relation to their nameplate capacity could be used to classify the purchase costs. The analytical requirements for this method would be material as it requires multiple classification assessments.

[34] Ex. NBP 5.05 Sch 3.3.

- Alternatively, a more comprehensive solution would recognize that the generation fleet is designed to be balanced as part of an ongoing system evolution to meet the overall customer load profile. In this case, existing and growing purchases on NBP's system should be recognized for their complementary role in interacting with the existing nuclear, hydro and thermal plant to serve the overall customer load profile, and simply be classified based on SLF.

The former method is more in-depth in that it considers both the demand-oriented role of thermal assets, and the energy-focused role, and growing importance, of purchases to meet NBP load requirements (particularly from imports and wind). However, the greater analytical requirements does not mean that this method is more accurate. The driver of the investment is minimizing the overall cost serve customer loads, and the customer loads are best represented by the evolving shape and relative importance of demand versus energy needs on the system – that is, the SLF. For this reason, the second method is both simpler and appropriately accurate.

In short, while SLF is currently a universal classification method to nuclear, hydro and thermal as a generating package (with purchases being classified 100% energy as an incidental supply), it is appropriate to recognize purchases as a part of the coordinated generating package and extend the SLF classification to purchases.

Recommendation 4: NBP generation plant (nuclear, hydro, thermal), as well as power purchase costs (where not explicitly for export purposes), should be classified to demand and energy based on the System Load Factor.

In measuring the SLF, the calculations currently include usage by all domestic classes, including interruptible sales.[35] However, the assets and costs classified by the method are not allocated to interruptible sales as part of the CCAS.[36] Except in cases where the utility clearly makes investments in generating plant tied to the ability to make interruptible sales, the classification of plant should reflect the basis of generation investment – firm domestic loads, exclusive of exports or interruptible domestic sales.

Recommendation 5: The calculation of the System Load Factor should be based on NBP sales exclusive of interruptible loads, except where such loads are included in system planning and the basis of capital investment.

[35] Ex. NBP 5.05, Add II
[36] Ex. NBP 5.05, Sch. 4.1, for example.

3.1.1 Out of Province Revenue

At the same time as classification of generation costs are analyzed, NBP is also classifying the net revenues received from out of province sales.[37] These net sales revenues are ultimately a credit to customers that offset the amounts the customer classes would otherwise pay for power.

NBP uses two different methods to classify out of province revenues.[38] The first is for capacity focused sales which are classified 100% to demand. The remainder are energy sales, which are classified to demand and energy on the SLF.

This method leads to a double counting of demand related revenue. Capacity-specific contractual supplies are allocated 100% to demand, but energy sales are classified to both demand and energy. On the same basis that capacity sales (which require "sufficient generating capacity to meet those demands"[39]) are allocated against the capacity resources that supply the capacity, energy sales should properly be allocated against 100% energy costs related to the assets that permit the energy component of the generation. Absent this symmetry, out of province sales are being excessively credited against capacity resources.

> **Recommendation 6: NBP out of province sales should be classified to 100% demand when related to capacity sales, and to 100% energy for other sales. The current classification method (100% demand for capacity sales and System Load Factor for all others) over-emphasizes the demand contribution towards these sales.**

3.2 ALLOCATION

NB Power has compiled a range of possible allocation methods, and then grouped these into six separate methodology combinations[40]:

[37] Ex. NBP 5.05, Sch 5.2.
[38] Ex. NBP 8.01, IR JDI-17 Supplementary Response, (c)(ii)
[39] Ex. NBP 7.03 page 54, IR JDI-17(b).
[40] Ex. NBP 8.01, pdf page 15, Supplementary response to JDI IR-19(l). The excerpt above excludes cases requested by intervenors that were not originally included in the NBP filing.

		Exhibit References					
		NBP05.05, NBP05.06, NBP05.12, NBP05.13, NBP07.08, NBP02.20 & NBP02.24	NBP06.01, NBP05.14, NBP07.09, NBP02.21 & NBP02.25	NBP05.08, NBP05.15, NBP02.22, NBP02.26	NBP05.09, NBP05.16, NBP02.23, NBP02.27	NBP06.02 (NBP05.17C) & NBP07.10 (NBP07.26C)	NBP06.03 (NBP05.18C) & NBP07.11 (NBP07.27C)
Costs	Classification	Average and Peak	Average and Peak with TOU	Probability of Dispatch	Marginal Cost	Seasonal Average and Peak Alternative #1 (Appendix J)	Seasonal Average and Peak Main Option (Appendix K)
Fixed Generation	Energy	Average Demand	Hourly Variable Cost	Probability of Dispatch	Marginal Cost	Average Demand	Seasonal Cost allocation
	Demand	Peak Demand	Hourly LOLP	Probability of Dispatch	Marginal Cost	Peak Demand	Peak Demand
Variable Generation	Energy	Average Demand	Hourly Variable Cost	Hourly Variable Cost	Marginal Cost	Seasonal Cost allocation	Seasonal Cost allocation
Out-of-province Energy Sales	Energy	Average Demand	Hourly Variable Cost	Probability of Dispatch	Marginal Cost	Average Demand	Seasonal Cost allocation
	Demand	Peak Demand	Hourly LOLP	Probability of Dispatch	Marginal Cost	Peak Demand	Peak Demand
Out-of-province Capacity Sales	Demand	Peak Demand	Hourly LOLP	Probability of Dispatch	Marginal Cost	Peak Demand	Peak Demand

Among the above methodologies, Average and Peak represents the approved methodology.

3.2.1 Peak/Demand Allocation

In respect of demand-related costs, NBP presently uses peak demand for allocation, based on the Coincident Peak (CP) for the winter. To implement this method, NBP uses the single highest forecast peak from the months of December, January, and February[41].

As noted in the previous sections of this testimony, NBP's system requires significant (and growing) attention to the difficulties in meeting the highest winter peaks. This constraint is appropriately captured by the use of a CP method for allocation.

In principle, the CP should be attempting to measure the highest peak demand expected to be imposed on the system. While the NBP method uses 3 CP allocation, the measure appears to ineffectively capture the true planning constraints associated with peak times. For example, looking to the last three years of data (2020/21 to 2022/23), the 3 CP values for the CCAS months of December, January, and February are as follows:[42]

[41] Because it is a forecast, NBP uses the energy projection combined with derived values for coincidence factor, load factor, and losses to arrive at the forecast peak by class.
[42] Data from Ex. NBP 7.15, IR PI-16(c) Attachment

	Dec	Jan	Feb	Highest	Lowest	Difference
	2020/21					
CP (MW)	2,708	2,698	2,767	2,767	2,698	2.5%
	2021/22					
CP (MW)	2,822	3,328	3,188	3,328	2,822	15.2%
	2022/23					
CP (MW)	2,628	2,891	3,392	3,392	2,628	22.5%

The above table highlights that only in one of the years in question are all three months a "peak" month – in 2020/21 all three peaks are within a small percentage difference of each other. In the other 2 years the lowest month is well below any reasonable measure of peak (15.2% to 22.5% below the peak). In 2020/21, where all 3 months were indeed close to the annual peak, the annual peak itself was very low, such that it poorly represents the usage associated with the level of investment that NBP must maintain in generating plant for the most acute system conditions.

Basing an allocation intended to capture peak conditions on usage during hours that are decided far from true peak conditions is misaligned to the purpose of representing the drivers of NBP's costs, which is the core purpose of the CCAS. Continued use of a CP allocation method should aim to capture true system peak conditions, not a broad winter average including months that experienced lower loads.

While the purest measure of system peak conditions would be represented by a single hour, it may be appropriate to use more than a single hour to avoid quirks of singular incidents that may drive volatility. For example, if the peak occurs during daylight hours, streetlighting may be allocated no costs. Similarly, the 2022/23 peak appears to have occurred on a Saturday (February 4, 2023), which may, if used as the sole input, lead to a different load profile for certain classes than the more typical weekday peak.[43] As a means to address to this issue, Manitoba Hydro uses a highest single winter peak measure for cost allocation (i.e., 1 CP), but derives the allocators based on reviewing the highest 50 daytime hours each year across the historical years being analyzed (an 8 year sample), regardless of the day or month as to when they occurred.[44] This apparent multiple CP method is different than the NBP 3 CP which does not use the highest peaks, but the highest single value selected from each of December, January and February. In Manitoba Hydro's last available full load research report (2015), the top 50 peaks all fall within 5.5% of the highest hour (4347 MW peak versus 4111 MW for the 50th hour). Across the years 2015-2022, the Manitoba Hydro gap from the top hour to the 50th hour varies from 4.97% to 7.58%, as

[43] Ex. NBP 7.16
[44] Manitoba Hydro 2017/18 and 2018/19 GRA, Appendix 8.3, page 2.

reproduced in Appendix B to this testimony.[45] In contrast, as noted above, NBP' variation is as high as 22.5% within the 3 hours used.

It may be appropriate to maintain a multiple CP measure for peak allocated costs (e.g., 3 CP or more), but this measure should focus on reducing volatility, not on broad seasonal averaging. To accomplish this, the method should focus on the highest peaks established in the winter season, not focus on one from each of December, January, and February. For example, the number of peaks should be representative of conditions no more than 5-10% below the peak hour, which for NBP would likely include approximately the highest 10 hours based on historical high peak years.[46] The purpose of expanding the input data would not be to mute the costing signal assigned to the uses which drive the highest peaks, it would simply be to help mitigate unusual load conditions (like a one-time peak that occurs on a Saturday, which is not typical of the NBP system).

In support of this measure, it is also noted that when the 3 CP method was originally adopted, Elenchus provided a report that recommended the 3 CP method because the 3 months in question (December, January and February) fell within 10% of the highest peak (February was 98.4% of the January peak, and December was 90.5% of January).[47] Elenchus also recommended load research be continued to eventually replace the allocator "with a multiple coincident peak allocator that is based on all hours of the year with demands within 10 percent of the system's peak hour demand once sufficient load research has been completed".[48] This is for now possible, and is consistent with the recommendation in this testimony.

To be clear – the purpose of multiple CPs should be to yield stability and better represent peak conditions, not to simply spread costs. For example, if the highest peaks always occur at night, then streetlights should be allocated a high relative share of the peak load responsibility, as they help cause these peaks. If, however, the peaks vary between night and day, then streetlights should be allocated peak demand costs based on mixed causation – in some years they drive the peak and in some they do not, so an averaged-out cost responsibility would be appropriate.

Recommendation 7: Use of a multiple coincident peak value for demand allocation (such as the current 3 CP) may be appropriate, but it should be based on the highest firm load hours of the year, regardless as to the month in which those hours occur, rather than the highest hour of each of December, January and February. It may also be reasonable

[45] Per MIPUG-MH-I-112c, data reproduced in Appendix B to this testimony.
[46] A review of the response to NBP 7.16 suggests that capturing the peak hours that were within 7.5% of the highest hour for 2021/22 would require the 11 highest hours, and for 2022/23 would require the 8 highest hours. This was performed by adding the CP reported for each class (excluding column I, which is simply a sum of columns J and K, and excluding column K which is interruptible load), and counting the number of hours higher than the highest hour less 7.5%.
[47] Ex. NBP 9.02 from Matter 271, page A3-8.
[48] Ex. NBP 9.02 from Matter 271, page A3-8 to A3-9.

to expand the set of hours to include those close to the peak (e.g., within 5-10%) which would be approximately the 10 highest hours in a year based on recent experience.

As alternatives to the CP method for allocating peak demand costs, NBP provides three other methods (none of which it recommends). The alternative methods offered by NBP all reduce the focus on the peak system planning driver:

- **Hourly Loss of Load Probability ("LOLP")** is a method that looks at each hour of the year, and the corresponding load shape across all hours, to assess the likelihood of reliability issues. This analysis is conducted based on the load conditions at the time the system requires new resources, not the Test Year in question. In this case, that load is a projection of 2030, and the load and generation balance is further adjusted to "calibrate" to the conditions where a next capacity resource is triggered.[49]

  Hourly LOLP is not a recommended method for allocation of peak demand costs, as it does not align with the way NBP actually plans its system. In this regard, NBP confirmed as follows[50]:

  > **Request:** Please confirm, or as necessary clarify and explain, that NB Power has historically designed its system to meet capacity requirements based on system peak demand and an applicable capacity margin of 20% in accordance with section 9.1 of the 2023 NB Power integrated Resource Plan (IRP), and not based on loss of load probability (LOLP).
  >
  > **Response:** Yes, NB Power plans on using a 20 per cent reserve margin as discussed in section 9.1 of the 2023 NB Power IRP.
  >
  > **Request:** Please confirm, or as necessary clarify and explain, that NB Power continues to plan its system to meet capacity requirements, including, in its most recent IRP, based on system peak demand and an applicable capacity margin of 20%, and not based on LOLP.
  >
  > **Response:** Confirmed. However, the 20 per cent capacity reserve margin is aligned with a loss of load expectation of 0.1 days per year. Please refer to section 9.1 of the 2023 IRP for additional information.

[49] Ex. NBP 7.03, page 75. IR JDI-24(d)(ii). The response notes: "All LOLP results are provided for a system at criteria (i.e. a 1-day-in-10- year loss of load expectation "LOLE" standard). Adjustments to the generation portfolio are made by adding or subtracting "perfect" generation to calibrate the system to criteria before determining LOLP hours."
[50] Ex. NBP 7.03, page 17. IR JDI-6(a).

Section 9.1 of the 2023 IRP discusses the "recent assessment of the reliability of the Maritimes Area" noting[51]:

> The same study indicates that the minimum reserve criterion for the Maritimes Area is 20 per cent. This means the capacity of generation resources must exceed the maximum firm peak demand by a minimum of 20 per cent in order to have sufficient generation available to meet reserve requirements. The IRP uses this 20 per cent reserve margin to plan for generation capacity.

In addition to these challenges with an LOLP-based allocation method, it is also unprecedented for use in allocating CCAS demand-related costs in Canada, which, as noted, are almost universally allocated on a CP basis.[52]

In support of the LOLP method, E3 notes that the function of LOLP is to spread out the allocation of demand costs to more hours, which they indicate is appropriate as more wind is added to the system. Specifically, E3 notes: [53]

> The LOLP weights are increasingly not driven by peak loads but rather by a combination of high loads and low supply (i.e. wind) days. It is not possible to know in advance which specific days of the month will contain low wind, and so each day within the month is weighted equally.

The issue with this response is it implies that in the past, CP methods were used because reliability needs (and thus investment) were driven by peak times, but in future reliability issues will be driven by low wind. This is a misunderstanding of the CP method, and a mischaracterization of systems with high wind penetration.

First, the CP method is not premised on the idea that capacity resources will be used only in peak hours. It is premised on the idea that the scale of capacity resource investment is driven by needs in peak hours. This will not change with higher wind penetration. The lowest temperature hours, with the highest loads, will still require the most investment in capacity resources to back-up both potential generating unit forced outages, and now also low wind output. The peak hours drive the investment – before and after wind. This is the same reason transmission is allocated on a CP basis. It is not because transmission has no function outside of the peak hour – it is

51 NBP 2023 Integrated Resource Plan, page 43-44.
52 Ex. NBP 7.13, page 4.
53 Ex. NBP 7.02, page 21, IR PI-9(e).

because the driver of transmission investment is meeting the most acute period of the year, and once that is achieved, no further investment is required to meet all the other lower load hours.

Second, the premise of adding wind to any system is that it will work as a complement to other resources, on an integrated basis. If one was only allocating the costs of backing up wind, a service that is sometimes known as *shaping* and *firming*, then the cost of the wind across all hours could be loaded with the costs of shaping and firming to yield an equivalent cost of a dispatchable resource. But this is not the purpose of CCAS. The CCAS is intended to allocate the costs of the entire generating fleet, including its ability to meet the highest and most challenging peak periods. Once costs are identified as capacity costs, based on the SLF classification step, those costs are already recognized to be associated with CP uses, not broad uses across extensive hours of the year.

The LOLP method is also flawed with respect to application to cost allocation in a Test Year, as the LOLP analysis is calculated quantitatively based on some hypothetical future load condition where new resources are required to be added. That is why the LOLP analysis uses the loads at 2030, consistent with the IRP which required new capacity as of 2029/30[54]. The method is effectively allocating costs for future hypothetical needs instead of embedded costs associated with the existing asset base and Test Year loads. In this manner, the LOLP method is poorly suited to a GRA cost allocation, based on the traditional standard of reflecting assets that are used and useful in Test Year. It is appropriate to consider methods that are robust across expected future system changes, not to quantitatively allocate costs across hypothetical potential future conditions that may or may not arise.

Finally, the LOLP method requires extensive amounts of load and system planning data that is typically confidential and difficult to test, which further limits its use as a method for cost allocation. This is the case here. The necessary data is not only confidential, but also far more granular than what NBP actually has available at the current time (e.g., loads by class by hour). It is also based excessively on long-term projections, not actual recorded use or forecast use in the Test Year. As such the data is synthetic, and subject to its own internal methodological concerns that cannot be readily tested in a normal GRA without access to extensive confidential information.

For all of the above reasons, the LOLP method to cost allocation is ill-suited to NBP's CCAS.

[54] NBP 2023 Integrated Resource Plan, page 47.

- **Hourly Probability of Dispatch ("POD")** is the second potential alternative method provided by NBP. This method relates to a fundamentally different concept of CCAS. Similar to LOLP, it requires an hourly assessment of the operation of the entire generation fleet. This gives rise to the same data testing, confidentiality and methodological concerns as for LOLP. However, the data requirements are even more onerous for POD because it must not only represent the loads by class by hour, it must also fully (and hypothetically) dispatch the entire system to meet that load hourly across the entire year.[55]

  The POD method similarly suffers from no precedent use in CCAS by any utility in Canada.

  More fundamentally, however, the POD method is entirely misaligned with the purpose of generation cost allocation in a CCAS. POD is a concept based on the premise that the value of a resource is derived from use. In the case of demand needs, however, the driver of investment in a resource is not its use; it is its availability for use when needed. NBP does not install 20% more generation capacity than its peak load because it expects to use these units under normal operating conditions (i.e., under a Test Year load forecast). It installs the 20% extra capacity because it must have this capacity available to provide safe and reliable electricity even in difficult unexpected conditions like extreme cold. In this way, it is these units' availability to dispatch – even if sparingly – that represent their significant value.

  In addition, a simple POD fails to consider the value of a resource to the system when it may happen to be used, focusing only on the binary concept of use versus non-use. E3 confirmed this is a valid concern with the POD method, noting the POD will identify resources as being dispatched (and thus included in cost allocation) even when that resource is providing little to no value. E3 suggests "(t)his is a limitation of the Probability of Dispatch method" and that "(t)his limitation is addressed by the Marginal Cost method, which considers marginal cost instead of generator dispatch in each hour to allocate costs."[56]

  Finally, POD is a conceptually unusual method to implement as it eliminates the need for Classification of costs to demand and energy. Under this method all generation costs are allocated directly by the POD, rather than first being identified as being related to demand or energy. A concern with this method is that it fails to recognize the key importance of reliability and major investments made to deliver firm capacity at peak times, treating the highest investment hours of the system in the same manner as any other hour. Such a method (cost

[55] Ex. NBP 7.03 page 7. JDI IR-4(a)(i).
[56] Ex. NBP 7.03, page 67. JDI IR-20(b).

allocation without classification) is used by none of the peer utilities surveyed by Elenchus.[57] This is a key flaw with the logic of this method.

For all of the above reasons, the POD method is not recommended as a CCAS method for NBP to adopt.

- **Marginal Cost** is the third allocation method provided by NBP. The potential to use marginal cost methods for CCAS have been widely-identified in the regulatory literature since the 1970s, as noted by Elenchus[58], and approaches to implementation have been in practitioners guides since at least the early-1990s, as evidenced by the manual from the National Association of Regulatory Utility Commissioners ("NARUC") provided in this proceeding.[59] Despite this long theoretical treatment in the literature, the adoption of marginal cost methods for CCAS is nearly zero. BC Hydro conducted an extensive survey in 2015 and concluded that only seven North American jurisdictions (all in the United States) had adopted marginal cost methods for cost allocation (one of which later reverted to non-marginal cost methods), and the remainder had adopted these methods in the "late 1970s and early 1980s".[60] Manitoba Hydro adopted weighting of energy allocation by export prices (a form of short-run marginal cost allocation) in 2005, but reverted to traditional CCAS methods in 2015, noting "the Board notes that marginal COSSs [Cost Of Service Studies] are rare in other jurisdictions" and that the "Board finds that marginal cost considerations are more appropriately addressed in the rate design stage of ratemaking and not the COSS stage".[61]

  Similarly, Elenchus has provided evidence in previous NBP proceedings that support this rare adoption of marginal costs as a primary methodology, even at the rate design stage, noting:[62]

  > It is generally accepted by economists that rates that are consistent with marginal costs would be more efficient; however, that approach to rate making is rarely used because rates based on marginal costs are unlikely to recover the utility's full revenue requirement and may not result in rates that are deemed to be equitable.

[57] Ex. NBP 7.13, page 4. Manitoba Hydro used to use an approach where classification was skipped and all generation costs were allocated to 12 different time periods throughout the year, with higher weighting to periods with higher export prices. However, this approach reflects Manitoba Hydro's highly integrated nature with export markets at the time, and the approach has since been abandoned.
[58] Ex. NBP 4.01, pages 20-21.
[59] Ex. NBP 7.07
[60] BC Hydro Rate Design Application, BCUC Proceeding No. 3698781, Exhibit B-1, pdf page 1155 of 4902.
[61] Manitoba PUB Decision 164/16, page 28 and 53
[62] Ex. NBP 7.18, pdf page 24; Elenchus evidence from 2015 as part of NBP CCAS review.

Limited use of marginal costs for blocked pricing or for interruptible sales is common, but this is fundamentally different than the Marginal Cost methods provided by E3 in this proceeding.

Elenchus further notes in response to interrogatories that "Elenchus is not aware of any utility that uses marginal cost for the purposes of weighting hourly allocation of generation fixed and/or variable costs" and that "Elenchus is not aware of any utility that uses hourly marginal cost for cost-of-service purposes".[63] More pointedly, Elenchus noted:[64]

> The Marginal Cost Method is, in the view of Elenchus, conceptually flawed as a basis for allocating the embedded historic costs of generation to customer classes unless the underlying goal is to enhance economic efficiency by designing rates that are based on the results of this method. Marginal costs are clearly viewed in the economic and regulatory literature as the ideal approach to establishing a rate design that is economically efficient, but they do not reflect the extent to which embedded historic generation costs are caused by the customer classes.

As the NBP CCAS is entirely oriented to allocating the Revenue Requirement (the embedded cost), and the CCAS is the tool used to specifically measure the extent to which these costs are caused by the various customer classes, a marginal cost method meets Elenchus definition as conceptually flawed.

The criticism of marginal cost CCAS methods extends to extensive concerns over how to match marginal costs to embedded costs, issues of elasticity and Ramsay pricing, the instability of marginal costs, the fundamental question of which marginal costs are of relevance (short-run or long-run), as well as extreme issues with confidentiality and commercial sensitivity of the data requirements. There appears to be no need to delve into these effectively fatal weaknesses to use of marginal cost methods for CCAS given the clear insufficiency of this method to suit NBP's needs.

Recommendation 8: Of the 3 novel CCAS methods analyzed by E3 (Loss of Load Probability, Probability of Dispatch, and Marginal Costs), none of these methods are practically viable or demonstrate any significant benefit for CCAS use on NBP's system. These methods are also largely unprecedented in Canadian CCAS practice, and each comes with extensive problems related to data availability, confidentiality and implementation in CCAS. None of the method should be adopted by NBP.

63 Ex. NBP 7.03, page 24. JDI IR-8(d)(v) and (vi)
64 Ex. NBP 4.01, page 24.

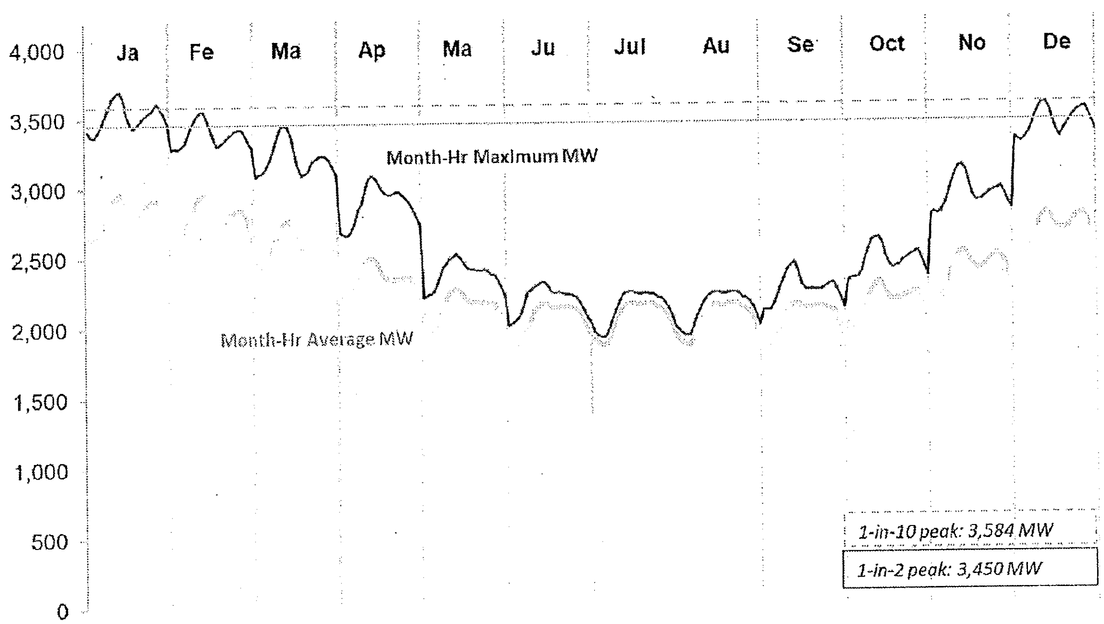
3.2.2 Loads Used For Demand Allocation

Among the challenges NBP faces today and that will likely increase into the future is the sensitivity to winter heating loads. With decarbonization and increased use of heat pumps, acute peak load conditions will become more difficult to serve without significant investment, particularly as more non-dispatchable renewable generation is brought online. This is outlined in the NBP decarbonization study, as follows[65]:

> The study assumes substantial amounts of load and peak growth due to electrification of end uses to reflect alignment with a Net-Zero decarbonization future.

The decarbonization study includes a graph that shows the impact of typical weather (the "average load requirements across all forty years of historical weather conditions") and extreme weather, as follows:

Figure 3-3. Total Load in 2030: Month-Hour Average and Maximum Load, MW



Note: Data above summarizes the month-hour average and month-hour maximums over the forty years of historical weather data.

The NBP system must be designed and operated to ensure reliability at the highest peak times. While these peaks can occur in a number of different months (December, January, February), when they occur the load pattern is generally well known – classes whose loads include material amounts of electric heating will drive increases in system demands, while classes that have relatively flat loads which are not sensitive to outside temperatures will not.

[65] Ex. NBP 7.05, page 23.

Proper cost allocation needs to consider that the drivers of investment (the *cause*) are the loads most subject to weather driven peaks. In the above example, the firm peak is near 3000 MW under normal conditions (the type of conditions represented by the load forecast) while the extreme peak well exceeds 3500 MW, and is due entirely to weather.

It would not be appropriate in the CCAS to allocate the costs of maintaining a system that can meet a peak well over 3500 MW, as is required for a system with large components of electric heat, across a projected load of only 3000 MW. This method will materially over-allocate the cost of maintaining this peak capacity to classes that do not contribute to the risk and uncertainty that causes the need to have the larger complement of generation installed.

For the purposes of demand cost allocation, NBP should adopt an allocation method premised on risk-adjusted load by class, such as at the P90 level (the 90th percentile of loads).

As an example of the variation, the following table sets out three points of comparison – the highest peak loads in each of 2021/22 and 2022/23 respectively[66], as compared to the 3CP allocation based on the status quo CCAS for 2023/24[67]:

Highest Peak (w/o Lg Ind IntSurp)	2021/22		2022/23		2023/24F (NBP5.05)		Difference from CCAS:	
	2022-01-27	*Allocator*	2023-02-04	*Allocator*	1/3 of 3 CP	*Allocator*	2021/22	2022/23
Residential	1,805,422	***57.2%***	2,094,291	***62.6%***	1,735,539	***55.7%***	**103%**	**112%**
GS1	*362,713*	*11.5%*	*338,488*	*10.1%*	*355,769*	*11.4%*		
GS2	*203,773*	*6.5%*	*141,420*	*4.2%*	*216,212*	*6.9%*		
General Service		**17.9%**		**14.3%**		***18.3%***	**98%**	**78%**
Sm Indust Dist	*83,601*	*2.6%*	*63,775*	*1.9%*	*87,160*	*2.8%*		
Sm Indust Trans	*4,551*	*0.1%*	*3,506*	*0.1%*	*1,726*	*0.1%*		
Small Indutrial		**2.8%**		**2.0%**		***2.9%***	**98%**	**71%**
Lg Indust Dist	*51,127*	*1.6%*	*29,983*	*0.9%*	*52,678*	*1.7%*		
*Lg Ind Trans Firm**	*334,159*	*10.6%*	*338,460*	*10.1%*	*376,563*	*12.1%*		
Large Industrial		**12.2%**		**11.0%**		***13.8%***	**89%**	**80%**
Lighting	-	*0.0%*	-	*0.0%*	*5,028*	*0.4%*		
Unmetered	*3,932*	*0.1%*	*4,212*	*0.1%*	*8,757*	*0.0%*		
Lighting and Unmetered		**0.1%**		**0.1%**		***0.4%***	**28%**	**28%**
Wholesale	306,866	***9.7%***	332,099	***9.9%***	278,455	***8.9%***	**109%**	**111%**
Total - Sum	**3,156,144**	***100.0%***	**3,346,234**	***100.0%***	**3,117,888**	***100.0%***		

* Lg Ind Trans Firm for 2023/24F includes LIREPP
The data for NBP 5.05 is hard entered, but is reproduced in Proceeding 552 Ex. NBP 2.51, Schedule 1.2, column 14

The data in the above table is understood to be at the CP times, referenced to generation (i.e., including losses related to each class' use). As shown in the above data, the allocators based on experienced CPs in 2021/22 and 2022/23 are well above that used for cost allocation in the 2023/24 CCAS. However, these are peaks for which the utility must plan its system, such as at the P90 level. The key consideration is

66 Ex. NBP 7.16, calculated using the customer class and total system peak (summed) not including the Large Industrial Interruptible and Surplus power customers (which are not included in capacity related measures).
67 Ex. NBP 5.05, Schedule 1.2 and Add II, and Ex. NBP 2.51 from Proceeding 552.

shown in the final 2 columns. For 2021/22 peaks, the current method using P50 load forecasts leads to some classes (Wholesale and Residential) being allocated less load in the CCAS than their peak use drives, and others, particularly Large Industrial and Lighting and Unmetered, being allocated more cost responsibility than the loads merit. For 2022/23, a year in which the peak is much higher and closer to the planning margins, the same allocation pattern holds, but also GS classes exhibit less responsibility for peak loads than the costs they are allocated in the CCAS.

An appropriate directional correction for this factor would be to develop the CP allocators based not on P50 load forecast values, but on values more akin to P90. Adjustments may be appropriate for known factors (e.g., the 2023 peak above on February 4, 2023 was on a Saturday – that would not likely be repeated in the P90 prospective load forecast). This method may still yield less allocation to the temperature sensitive classes than a full allocation of the CP planning responsibility that they cause (i.e., if loads are above P90, which they are expected to be in one year out of 10), but is would be an improvement over ignoring this factor. Further, it would help ensure in future if more temperature sensitivity becomes embedded in the various class loads such as through increased use of heat pumps, this cost responsibility allocation occurs naturally in the CCAS.

It is also noted that NLH has similarly been directed to "...review the contribution of different customer classes to the uncertainty parameters in its planning studies (e.g. P50 vs P90), to ensure the calculation of peaks used in the Cost of Service study appropriately reflect the contribution of the different customer classes to the CP used for planning purposes...."[68]

> **Recommendation 9: For the purposes of Coincident Peak allocation in the CCAS, the peak load responsibility should be based off the risk or weather-adjusted load forecast, such as at the P90 level, rather than the P50 level.**

3.2.3 Energy Allocation

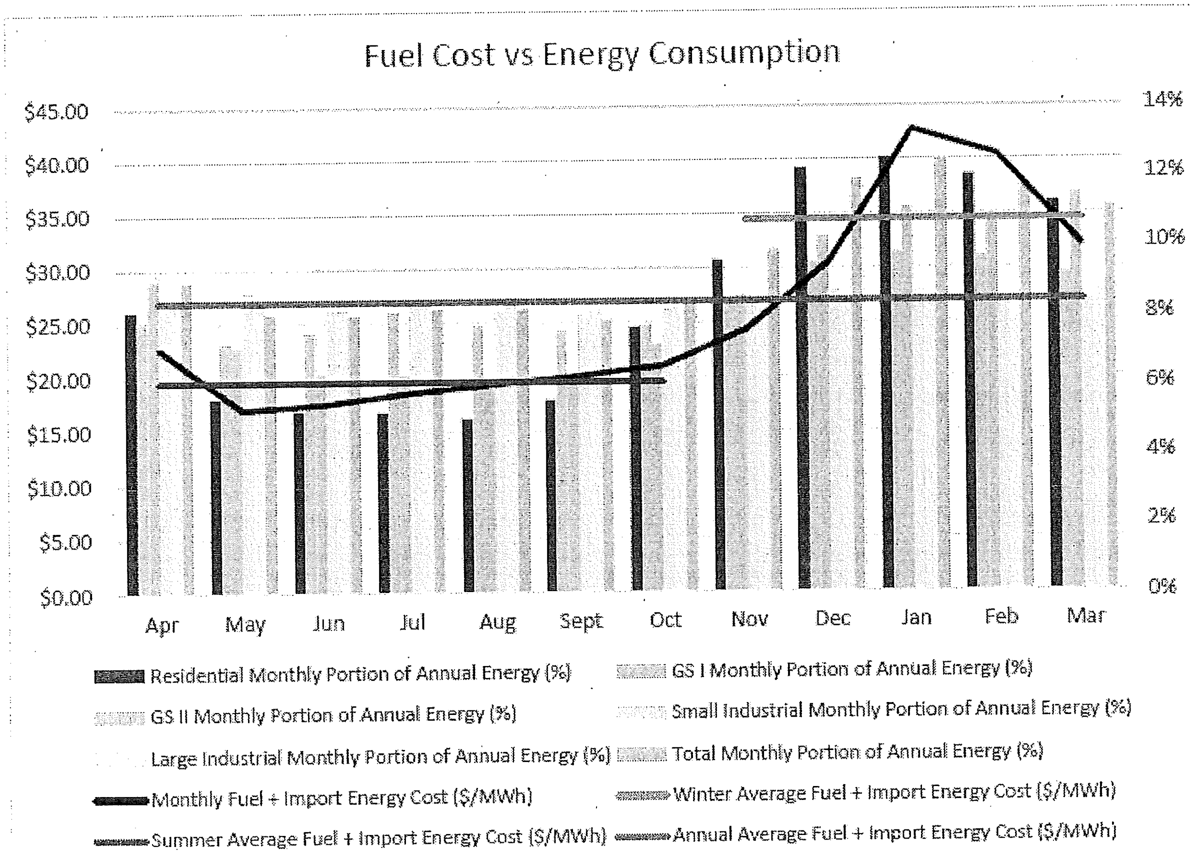
Costs classified to energy comprise two basic forms – those that are fixed, such as a portion of the capital costs of hydro or nuclear plant – and those that are variable and incurred as energy is consumed, such as fuel and power purchase costs.

The impetus for the current CCAS review revolves primarily around costs that are classified to energy. As a result of directions provided in Matter 271 (2016), NBP commissioned analysis on options to implement seasonal allocation of energy costs in CCAS. This first analysis was filed with Matter 357 (2017)[69]. The primary focus was on variable costs, which is appropriate – fixed costs classified to energy do not vary

[68] Newfoundland and Labrador Board of Commissioners of Public Utilities, Order P.U. 37(2019) Schedule A page 3 of 5 (pdf page 9 of 11)
[69] Ex. NBP 2.03 from Matter 357.

with usage (e.g., hydro plant depreciation is a cost incurred in part to provide energy, but the depreciation expense is not increased or decreased depending on whether a customer uses energy in winter or summer).

From the outset, it was apparent that there was a clear seasonal or monthly pattern to the incremental costs to serve customer loads (fuel, import, and power purchase costs). This was demonstrated in the following excerpt from NBP's evidence at that time:[70]



Put simply, the periods of highest variable costs to serve load (fuel and net imports) coincide with load from classes that disproportionately consume energy in winter. This figure is from a 2017 report – the relationship may change in future as more of the load is served by purchases, and less by fuel. However, it is not clear how this relationship will evolve.

The above figure highlights a clear cost trend that should be reflected in the CCAS.

70 Ex. NBP 2.03 from Matter 357, Appendix 1

Recommendation 10: Energy cost allocation for NBP should include consideration of the differing incremental cost of energy production in different time periods, rather than an oversimplification based on averages at the level of annual usage.

In the current proceeding, the evidence is that the pattern of higher incremental costs matching winter intensive loads continues to hold. This can be seen by comparing the energy allocator used in various CCAS models of different time-step granularity. Three different time steps for CCAS analysis are provided:

1) **Annual time step granularity:** This method represents the status quo, and is illustrated by various CCAS models associated with Appendices E and F[71] and their variants.

2) **Seasonal (winter versus summer):** This time step is contained in Appendices J and K and their variants[72]. Note that seasonal cases are appropriately compared to Appendix E for the status quo, as they used the input loads per the GRA load forecasts and not the loads based on the E3 analysis.

3) **Full hourly time step granularity (Time of Use, or "TOU"):** This CCAS method is contained in Appendix G and its variants[73], and is appropriately compared to Appendix F for the status quo, as it uses the input loads per the E3 load modelling.

The different cases also apply the energy allocators to different combinations of costs – e.g., only variable, also fixed, also purchases and net export revenues, etc. For this reason, it is not entirely accurate to compare dollars allocated, but it is appropriate to compare the allocator itself (what percent of total dollars that are classified to energy are allocated to each class).

The table below sets out the energy allocator under the status quo method (annual) versus the refined methods (seasonal and hourly).

[71] Ex. NBP 5.05 and 5.06.
[72] Ex. NBP 6.02 and 6.03, and confidential exhibits 5.17C and 5.18C.
[73] Ex. NBP 6.01.

	Annual Allocator	Seasonal Allocator	*Change*	Annual Allocator	Hourly (TOU) Allocator	*Change*
Data Source	Ex. 5.05	Ex. 6.03		Ex. 5.06	Ex. 6.01	
Customer Class						
Residential	43.67%	44.67%	*0.99%*	44.94%	48.23%	*3.29%*
General Service						
General Service I Primary Distribution	5.47%	5.40%	*-0.07%*	5.66%	5.35%	*-0.32%*
General Service I Secondary Distribution	8.43%	8.32%	*-0.11%*	8.50%	8.02%	*-0.48%*
General Service II Primary Distribution	2.46%	2.50%	*0.04%*	2.40%	2.51%	*0.10%*
General Service II Secondary Distributior	1.68%	1.71%	*0.03%*	1.60%	1.67%	*0.07%*
Total Lights and Unmetered	18.04%	17.92%	*-0.13%*	18.17%	17.54%	*-0.63%*
Small Industrial Transmission	0.11%	0.11%	*0.00%*	0.14%	0.14%	*0.00%*
Small Industrial Distribution						
Small Industrial Primary Distribution	2.41%	2.35%	*-0.06%*	2.41%	2.21%	*-0.20%*
Small Industrial Secondary Distribution	1.06%	1.04%	*-0.03%*	1.03%	0.95%	*-0.09%*
Total Small Industrial Distribution	3.48%	3.39%	*-0.09%*	3.45%	3.16%	*-0.29%*
Large Industrial						
Large Industrial Distribution	2.44%	2.35%	*-0.09%*	2.48%	2.18%	*-0.30%*
Street Lights & Unmetered						
Street Lights	0.15%	0.15%	*0.00%*	0.20%	0.20%	*0.00%*
Unmetered	0.34%	0.33%	*-0.01%*	0.28%	0.26%	*-0.02%*
Total Lights and Unmetered	0.49%	0.47%	*-0.01%*	0.47%	0.46%	*-0.01%*
Transmission						
Large Industrial Transmission	21.50%	20.81%	*-0.69%*	20.08%	17.95%	*-2.12%*
Interruptible/Surplus	0.00%	0.00%	*0.00%*			*0.00%*
LIREPP	2.01%	1.95%	*-0.07%*	1.88%	1.68%	*-0.20%*
Total Lights and Unmetered	23.52%	22.76%	*-0.76%*	21.96%	19.63%	*-2.32%*
Wholesale Sales	8.26%	8.34%	*0.08%*	8.39%	8.66%	*0.27%*
Total	**100.0%**	**100.0%**		**100.0%**	**100.0%**	

As shown in the above table, adopting a more granular reflection of the load drivers of energy cost leads to increased allocation to classes that are expected to make more use of energy in costlier periods. The implications are material. The more granular the method (from annual, to seasonal, to hourly TOU) the more that increasingly refined information changes the cost allocation. For example, in the case of the residential class, if each unit of energy in the year is treated as being equivalent, the class is responsible for 0.99% less of NBP's energy costs than if an appropriate recognition of winter/summer seasonal cost differentiation is included in the analysis (left-hand side of the table). Given the allocation relates to at least in excess of $500 million in fuel and purchased power costs alone (over $900 million if including fixed costs classified to energy), the impact of the difference is material.

However, the impact is much larger once the more refined full hourly cost profile of serving the residential load is analyzed. As shown in the right-hand side of the table, the comparison between status quo annual allocation and hourly allocation is 3.29% of energy classified costs. In short, by allocating energy costs on a simplified annual basis, the residential class avoids being allocated responsibility for 3.29% of the total variable annual energy cost that is caused by their hour-by-hour usage.

The opposite trend occurs for high load factor customers such as the industrial transmission class. Recognition of seasonal differences in costs reduces and corrects for 0.76% of the energy costs otherwise being allocated to industrial transmission customers under the simplified annual method that would not be so allocated under a more refined method. However, this gap grows to 2.32% once the full hourly time step granularity is included.

The effect is smaller for small industrial, General Service, and wholesale, who appear to have loads that are much closer to being reasonably represented by the current annual method.

The merits of a more granular energy allocation relate to the basic principle noted earlier in this document, that for practical purposes, energy cannot be entirely divorced from the time it is delivered. Energy delivery to customers yields value and meets load needs when it is delivered at the time-period when it is needed – a customer would not be satisfied with having their energy demand for heating met with a summer delivery of kilowatt-hours. Energy therefore has differing incremental costs in different time periods.

The analysis in the E3 report with respect to developing an hourly time step allocation appears to be sound in terms of its development and quantification. The hourly time step, or TOU allocation, should be considered the analytical ideal for CCAS purposes. However, there are also challenges to implementing the hourly TOU for energy allocation in each future CCAS, as follows:

1) The input data is considered confidential by NBP.
2) The development of hourly loads requires analytical methods to produce the required granular loads, which leads to the potential for inaccuracy; although, this will become less of a concern as smart meter data becomes available to NBP in coming years.

The proceeding record only provides three levels of granularity – annual, seasonal, and hourly. At times in the past, monthly models (12 periods in a year) have also been produced. Although monthly models were not provided in this proceeding, a similar analysis was conducted on the seasonal versus monthly models provided in Matter 529[74] and there was barely noticeable difference in the allocator between a seasonal allocation and a monthly allocation. This further conclusion suggests that the material differences between a seasonal allocation method (2 periods in a year) and an hourly allocation method (8760 periods in a year) cannot be achieved due to simply shortening the time step (increasing the number of periods) in any random way. It could be reasonably expected that the improvements seen between 2 time periods and 8760 time periods could be achieved by some middle ground short of 8760; however, that middle ground would have to include consideration of other approaches to division, such as on-peak versus off-peak hours. It is noted that when Manitoba Hydro used a weighting to energy allocation (prior to 2015), 12 time periods were used – 4 seasons, and 3 weekly patterns, of on-peak, shoulder, and off-peak hours (including consideration of 7 am to 11 pm hours, weekends versus weekdays, holidays, etc.). When reviewing the methods in 2012, Manitoba Hydro received recommendations from their CCAS consultant that they may want to explore hourly weighting, but noted:[75]

> MH is less convinced that using hourly pricing as weights would offer any significant improvement over the current 12 periods (four seasons, peak/ shoulder/ off-peak) in terms of recognizing energy price variability. The current approach groups similar hours together and offers greater stability to the allocation procedure. MH notes that an earlier move (from a two season, peak/ off-peak to the current 12 period) weighting did not result in a significant change to allocation results.

A distinction in the energy product being produced or supplied related to peak/shoulder/off-peak hours is common in energy market trading.

For the purposes of considering an alternative method, the hourly dispatch data and customer class usage data from the E3 files[76] was aggregated to test whether a less granular method than 8760 hours could still reasonably represent the system cost profile. To consider an alternative time step, the following method was applied:

---

[74] Ex. NBP 7.16 and 7.17 from Matter 529. The comparison was done by using Schedule 4.3, summing the allocated fuel and purchased power costs to each class, as a percentage of the total cost for fuel and purchased power.
[75] Manitoba Hydro 2015 Cost of Service Methodology Review, Appendix 4, page 8 of 25.
[76] Ex. NBP 2.31C. A non-populated model was provided in Ex. NBP 3.01.

- A four-period time step was used, focused on Winter (December, January, and February, March) versus non-winter (all other months), and on-peak (weekdays 7 am to 11 pm) versus off-peak (all other hours). The month and hours in question were chosen as being the highest usage.
- Customer loads (energy use in each hour) were derived from the Tab "Active Hourly Load Data" associated with the four time periods.
- Dispatch costs were derived from the tab "Active Production Data" measured in percentage of the annual dispatch cost occurring in each hour.
- A sumproduct was calculated across four periods, in the same manner that E3 calculated the sumproduct across 8760 periods, in the tab "Allocation Factors".

The results of this analysis are provided in the appended Excel file, and yield the following classification results. Note that not all classes are represented in full in the E3 data file, however the three allocation ratios shown are derived from the same original data source so are understood to be internally consistent:

[PAGE REDACTED]

The challenge at this time is determining whether the substantial improvement provided by the 4 time period method compared to the status quo is sufficient, or whether the full implementation of hourly TOU is merited. The four-period method is less granular, and thus may make both the analytical effort required to complete the CCAS more practical, and also increase the potential that key parts of the CCAS modelling could be made available for public (non-confidential) review.

However, if the simplification benefits of a four-period method are not of consequence (e.g., if the data will be just as complicated to compile, and there will be no increase in transparency) then it is recommended that NBP adopt the hourly TOU time step to ensure the CCAS accurately yields fair results.

> **Recommendation 11: The most accurate method for allocating energy-related variable costs, including power purchases, is the hourly time-step TOU method. Other methods for energy-allocation other than TOU may be suitable, in the event they are more practical, so long as they closely mimic the results from the hourly TOU method.**

> **Recommendation 12: Use of a 4-period time step for energy allocation (winter/non-winter, on-peak/off-peak) appears to permit most of the benefits of the hourly TOU method to be achieved at a far less data intensive scale. However, if this method does not ultimately yield the majority of the accuracy benefits of the more granular hourly TOU method, with a simpler and less data-intensive model, the TOU based allocation of variable energy costs should be adopted.**

It should be noted that the impact of adopting a TOU based improvement is material. NBP produced a CCAS model that maintains status quo for all demand-related costs, as well as fixed energy-related costs, but uses TOU granular allocation for energy related variable or incremental costs, as well as out of province sales[77]. This method yielded fully allocated costs that, compared to the status quo, varied by over $30 million for the residential class (approximately 3%), over $3 million for the Small Industrial class (over 5%), almost $1 million for the streetlights and unmetered class (over 5%) and over $25 million for the large industrial class (over 6%). This scale of impacts is relevant to assessing where each customer fits in the Revenue to Cost Ratio ("RCR") and would have practical impacts on the level of rate increases sought by class. With the other methods outlined in this testimony (e.g., SLF classification of purchases, energy allocation for out of province sales, etc.) the impact may well be larger than calculated in the above analysis.

[77] Ex. NBP 8.02.

3.2.4 Precedent for Refined Energy Allocators

As part of NBP's filing, Elenchus provides the peer review of utilities noting "(n)o utility consider seasonality with respect to allocating energy-classified costs" and repots the energy allocation of all seven peer utilities as being based on "annual energy".[78]

There are two issues with the Elenchus peer review:

First, as noted earlier in this testimony, Elenchus has failed to include FortisBC, the large vertically integrated electric utility serving a significant portion of British Columbia. FortisBC's CCAS method allocates energy-related power supply (i.e., generation) costs based on the usage by each customer class in each month, as follows: [79]

> Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. For purposes of monthly power supply costs, the energy in each month was used as the allocator.

NBP and Elenchus were made aware that FortisBC uses a monthly allocation method as part of the April 11, 2023 motion filing in Matter 529.[80]

Second, Elenchus also reports Nova Scotia Power ("NSPI") as using annual energy as the allocator for energy costs. This is not correct. NSPI classifies fuel costs as well as imports as 100% energy-related and allocates these costs to each class in their CCAS (Above the Line, or "ATL") based on monthly usage, as follows:[81]

> For ATL classes, NS Power's fuel costs will be classified as 100 percent energy related. These costs will be allocated to each class based on its 12 relative contributions to monthly energy requirement.

NBP and Elenchus were previously provided evidence in Matter 271 describing the Nova Scotia Power method.[82]

At this time, it does not appear that any Canadian vertically integrated regulated electric utility uses an on-peak/off-peak distinction in Cost Allocation. As noted, such a method was used by Manitoba Hydro based on the relative value of energy in export markets, but this was changed in 2016 concurrent with

[78] Ex. NBP 7.13, page 1 and 4.
[79] BCUC proceeding 1598939 FortisBC 2017 Cost of Service Analysis and Rate Design Application, Ex. B-1, pdf page 168-170 of 715. COSA Report, pages 28-30.
[80] JD Irving Limited Notice of Motion, April 11, 2023, paragraph 38.
[81] NSPI 2020-2022 Fuel Stability Plan Application, June 27, 2019. Proceeding M09288. Page 76 of 81. Exhibit N-1.
[82] Ex. JDI 1.01 and JDI 3.01

export sales being less emphasized in the Manitoba Hydro CCAS methods.[83] As the method is simply a refinement on well-accepted embedded cost CCAS energy allocation methods, the lack of precedence would not appear to be a strong factor opposing adoption by NBP.

[83] Manitoba PUB Order 164/16

4.0 INDUSTRIAL TRANSMISSION CLASS DESIGN

EUB Matter 529 addressed the merits of updating the NBP class structure, including NBP's proposal to create a transmission-connected class. In the Reasons for Decision, the EUB noted:[84]

> Paragraph 49: ... the Board is satisfied that the proposal is reasonable for the purpose of conducting further analysis and refinement before final Board approval of detailed rate classes and related rates because:
>
> > a. it would reduce potential rate differences between customers with similar costs to serve, thereby reducing inequity in the existing rate structure;
> >
> > b. it forms a reasonable basis for the classification of distribution-connected customers; and
> >
> > c. subject to the Directions in paragraph 69, NB Power's plan to develop the proposal for final approval is reasonable, including the study of the potential segmentation of transmission-connected customers.
>
> ...
>
> Paragraph 69: ... The Board, therefore, directs NB Power to study, consider and model a single transmission-connected class and further segmentation of transmission-connected customers, including but not limited to segmentation of those transmission-connected customers with demand exceeding 25 MW. The Board directs NB Power to complete this work before seeking the Board's approval of new classes and rates for commercial and industrial customers and to report the results to the Board as part of its application for approval of new classes and rates for commercial and industrial customers.

In the current proceeding, NBP has provided modelling of the CCAS using new classes, including the transmission connected class. NBP is not formally requesting approval of the new classes and rates as part of this proceeding. However, a key consideration in Matter 529 was whether one transmission-connected class would be sufficient, or whether cost characteristics of a large transmission connected class (such as >25 MW) may be sufficiently distinct from smaller transmission connected customers as to support subdivision of the class.

[84] Reasons for Decision, Matter 529.

CCAS and cost allocation was only one reason for potential subdivision of the transmission class, but not the only reason; others include a better opportunity to tailor rate designs, for example.

The class delineation is not a matter for decision at this time (it is not part of the requested approvals, and the Reasons for Decision from Matter 529 noted the Board would not address final approvals until NBP applies for implementation of the new classes). However, it is noted that NBP cites that division of the industrial class into <25MW versus >25MW classes would show CCAS responsiveness in that the results would be "sensitive ... to losing or gaining a very small number of larger customers".[85] This is precisely the expected outcome, as even a very small change in the customer make-up of a class of very few, very large customers should flow through to CCAS results. Indeed, the opposite – a lack of sensitivity to losing or gaining a very small number of large customers – would indicate a weakness in the class design. It should also be noted that the current CCAS modelling does not include the full industrial load complement (it excludes Interruptible, Surplus and Large Industrial Renewable Energy Purchase Program ("LIREPP") loads) so the CCAS results should be interpreted carefully for this reason.[86]

On balance, while no decision is required today, the presumption in favour of maintaining a subdivided large industrial class (<25 MW and >25 MW) should be maintained, pending finalization of the CCAS methods and a future application to implement the new classes.

[85] Ex. NBP 5.02, page 13.
[86] Ex. NBP 5.02, page 13.

APPENDIX A:

RESUME

PATRICK BOWMAN

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AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including Depreciation
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

BOWMAN ECONOMIC CONSULTING INC., WINNIPEG, MANITOBA

2020 – current – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation. Member, Society of Depreciation Professionals

Sample Projects:

For Northwest Territories Power Corporation (2020-Present; with previous involvement 2000-2020): Provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity). Support to Government of the Northwest Territories on Crown utility governance, rate policy matters, and project development.

For Northwest Territories Energy Corporation (2021-Present, with previous involvement 2003 - 2013): Provided analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects. Assist in planning stages and contract review for new LNG supply to Inuvik. Assist in Board of Director's review of corporate roles for commercial versus regulated activities.

For the BC Association of Major Power Consumers (2020-Present; with previous involvement 2014-2020): Support for review of BC Hydro Revenue Requirement, Depreciation, Cost of Service, Rate Design, Interruptible Rates, and stepped industrial rates.

For J. D. Irving Ltd. (2022-Present); previous involvement 2017-2018): Support in regulatory proceedings before the New Brunswick Energy and Utilities Board on matters of Revenue Requirement, customer class and rate design, and smart meter implementation.

For the PEI Federation of Agriculture (2023-Present): Support in regulatory review of Maritime Electric Rate Design proceeding.

For the Industrial Group of Nova Scotia Power Inc. (2024-Present): Technical support to Cost of Service working group and negotiations on methodology.

For the Manitoba Public Interest Law Centre (2024): Technical support to working group for Brokenhead Ojibway Nation in consultation process with Manitoba Hydro regarding new development and licencing of existing projects on the Winnipeg River and Lake Winnipeg Regulation.

For confidential client (2021-2023): Assist in investigations regarding potential hydrogen development opportunities in Canada.

For Vale Newfoundland (2022-2023): Assist in negotiations regarding new industrial contract and interruptible power framework.

For Corner Brook Pulp and Paper (2021-2022): Assist in negotiations regarding new industrial contract and interruptible power framework.

INTERGROUP CONSULTANTS LTD., WINNIPEG, MANITOBA
1998 – Present – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability.

Sample Projects:

For Manitoba Industrial Power Users Group (1998 - Present): Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (CentraGas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.

For Industrial Customers of Newfoundland and Labrador Hydro (2001 - Present): Prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities. Appear before PUB as expert in cost of service and rate design matters. Assist in review of rate mitigation options for major new generation and transmission; provide evidence before PUB.

For Nelson Hydro (2013 - Present): Development and updating of a Cost of Service model. Support in regulatory filings before the BC Utilities Commission including Revenue Requirement and Generic Cost of Capital.

For the Office of the Utilities Consumer Advocate of Alberta (2016 - Present): Analysis and strategic support of Government agency representing the interests of small utility customers. Addressed matters of utility rates and asset depreciation matters, covering electrical transmission, distribution, gas transmission, distribution, project development, and regulated utility service providers.

For the Ontario Energy Board (OEB) (2024-Present): Review regulatory commission policies and practices with respect to intervenor participation, including Consumer Advocate options, budgets, etc.

For the Ontario Energy Board (OEB) staff (2022-2023): Support the OEB staff in the Enbridge Gas Distribution 2024 rate re-basing application, focused on matters of utility assets and depreciation.

For Industrial Gas Users Association of Manitoba (2019-2022): Support for cost of service and rate design matters. Testimony before the Manitoba Public Utilities Board.

For Vancouver Airport Fuel Facilities Corporation (2018-2022): Provide analysis and evidence in support of tolls for common carrier jet fuel pipeline, before the BC Utilities Commission.

For City of Chestermere (2015 - 2022): Analysis of various rate proposal from Chestermere Utilities Inc. to the City of Chestermere.

For a law firm (2021-2022): Provide analysis in support of hydro generation valuation in northwestern Ontario.

For Taxi Coalition of Manitoba (2021): Support for regulated vehicle insurance rate design, provided by Crown insurer. Testimony before the Manitoba Public Utilities Board.

For Jamaica Public Service (2018-2020): Assist in preparation of regulatory rate filing, including cost of service, revenue requirement, and plans to address utility losses and power theft.

For Government of Ontario (2018): Support to department undertaking and supporting preparation of a Modernization Review of the Ontario Energy Board.

For Yukon Energy Corporation (1998 - 2015): Provide analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.

For City of Swift Current (2013 - 2014): Utility system valuation.

For Municipal Customers of City of Calgary Water Utility (2012 - 2013): Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).

For Yukon Development Corporation (1998 - 2012): Prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

For NorthWest Company Ltd. (2004 - 2006): Review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local *communities in resolution of outstanding compensation claims related to hydro projects.*

Sample Projects:

For Government of Canada – Justice (2022-2023): Provide opinion evidence for proceeding before the Specific Claims Tribunal regarding transmission line valuation for 1950s transmission line crossing reserve land.

For the Government of the NWT (2021-2023): Assist in developing rate strategies and operational costing for major new generation and transmission facilities in NWT.

For Kivalliq Hydro-Fibre Link (2020-2022): Review and provide comment on drafts of business case for new transmission and fibre optic link to Nunavut.

For Hualapai Tribal Utilities (2017-2018): Support Tribal utility association in preparation of feasibility study to take over operations of power distribution on tribal lands.

For Government of NWT (2015-2016): Assist in analysis for hydro system resiliency study in response to Snare River drought.

For New World Dairy (2015-2017): Assist in negotiations regarding Non-Utility Generation and interconnection with Newfoundland Hydro

For Yukon Energy Corporation (2005 - 2015): Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

For Northwest Territories Power Corporation (2005 - 2012): Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out interconnect to southern jurisdictions. Conduct business case analysis regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

For Tolko Manitoba (2014-2015): Assist in negotiations with Manitoba Hydro regarding expansion of steam generation capabilities.

For Kwadacha First Nation and Tsay Keh Dene (2002 - 2004): Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

For Manitoba Hydro Power Major Projects Planning Department (1999 - 2002): Initial review of socio-economic impacts of proposed new northern generation stations and transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

For Manitoba Hydro Mitigation Department (1999 - 2002): Provided analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

For International Joint Commission (1998): Analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.

For Nelson River Sturgeon Co-Management Board (1998 and 2005): An assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

GOVERNMENT OF NORTHWEST TERRITORIES, YELLOWKNIFE, NORTHWEST TERRITORIES

1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony on all areas of Revenue Requirement, including Depreciation	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation, Support to Legal Counsel	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
Newfoundland Hydro	Depreciation Methodology	Analysis, Support of Expert Witness, Advisor to Legal Counsel	NLPUB	Newfoundland Industrial Customers	2012	No
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Testimony and Negotiated Settlement, including Depreciation	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlemen
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on Depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlemen
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on Depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation for SCADA Depreciation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence including Depreciation	AUC	UCA	2018	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018	Yes
Newfoundland Hydro	Cost of Service Methodology	Analysis and Case Preparation	NLPUB	Newfoundland Industrial Customers	2018	No
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony. Included Depreciation Rate Mitigation Options	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
BC Hydro	Fiscal 2020 to 2021 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence	BCUC	Association of Major Power Consumers of BC (AMPCBC)	2019-2020	Yes
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence on Depreciation and Valuation matters	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coalition	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis and support of intervenor evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWT PUB	NTPC	2022	No
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II (Cost of Service and Rate Design) Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	No - Written Process only
Centra Gas Manitoba	2021 Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence	MPUB	Industrial Gas Users of Manitoba (IGU)	2021-2022	No - Written Process only
BC Hydro	Fiscal 2022 to 2025 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence, primarily focused on depreciation	BCUC	AMPCBC	2022	Yes
DERS	2023 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2023	No - Negotiated Settlement and written process
EDTI	2023-2025 Transmission Facility Owner Revenue Requirement	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement and written process
BC Hydro	2021 Intergrated Resource Plan	Analysis, Preparation of Intervenor Evidence	BCUC	AMPCBC	2023	Yes
Enbridge Gas Inc (EGI)	2024 Rebasing	Analysis, Preparation of Intervenor Evidence	Ontario Energy Board (OEB)	OEB Staff	2023	Yes
New Brunswick Power	Matter 529 - 2022 Rate Design Application	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2023	Yes
Manitoba Hydro	2023-23 and 2024-25 GRA	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2023	Yes
Manitoba Hydro	SCT 4002-12 Brokenhead Ojibway FN vs HMTK	Opinion on Transmission Line Valuation	Specific Claims Tribunal	Government of Canada	2023	No - Negotiated Settleme
NTPC	Hay River Franchise Disposition	Analysis, support preparation of regulatory principles, rate impacts	NWT PUB	NTPC	2024	Yes
Nelson Hydro	Generic Cost of Capital Review - Stage 2	Support to Nelson Hydro on preparation of utility evidence	BCUC	Nelson Hydro	2024	No

APPENDIX B:

Manitoba Hydro Coincident Peak Data

1.0 INTRODUCTION

Manitoba Hydro 2015 to 2022 peak load data from 2023/24 GRA and 2024/25 GRA, from response to MIPUG/MH-I-112c Attachment.

2015		2016		2017		2018		2019		2020		2021		2022	
Date/Time	kW	Date/Time	kW	Date/Time	kW	Date/Time	kW	Date/Time	kW	Date/Time	kW	Date/Time	kW	Date/Time	kW
2015-01-12 09:00	4,347,742	2016-12-17 18:00	4,326,004	2017-01-13 09:00	4,452,282	2018-01-12 09:00	4,402,558	2019-01-29 19:00	4,590,004	2020-01-16 09:00	4,425,378	2021-02-11 09:00	4,552,215	2022-01-07 18:00	4,519,281
2015-01-04 18:00	4,325,546	2016-12-18 18:00	4,297,382	2017-01-13 08:00	4,389,753	2018-01-12 08:00	4,359,843	2019-01-29 20:00	4,571,959	2020-01-16 08:00	4,370,402	2021-02-11 08:00	4,542,210	2022-02-03 09:00	4,503,134
2015-01-07 09:00	4,317,321	2016-12-17 19:00	4,283,471	2017-01-13 10:00	4,378,905	2018-01-15 09:00	4,353,093	2019-01-31 09:00	4,565,579	2020-01-16 18:00	4,361,045	2021-02-12 09:00	4,541,057	2022-01-07 09:00	4,492,710
2015-01-04 19:00	4,311,567	2016-12-16 18:00	4,278,302	2017-01-12 18:00	4,313,214	2018-01-15 08:00	4,329,104	2019-01-30 09:00	4,562,379	2020-01-16 10:00	4,348,682	2021-02-08 09:00	4,509,049	2022-02-17 08:00	4,479,301
2015-01-12 08:00	4,289,546	2016-12-15 09:00	4,271,920	2017-01-12 19:00	4,300,062	2018-01-15 18:00	4,308,993	2019-01-30 08:00	4,555,627	2020-01-16 19:00	4,336,798	2021-02-08 08:00	4,489,993	2022-01-07 17:00	4,473,290
2015-01-04 20:00	4,288,477	2016-12-15 08:00	4,258,258	2017-01-11 18:00	4,289,234	2018-02-12 08:00	4,293,900	2019-01-29 18:00	4,551,661	2020-02-13 08:00	4,288,965	2021-02-08 19:00	4,482,989	2022-01-07 10:00	4,466,880
2015-01-06 19:00	4,276,763	2016-12-14 18:00	4,257,468	2017-01-12 20:00	4,286,040	2018-01-12 10:00	4,291,756	2019-01-29 21:00	4,550,176	2020-01-16 20:00	4,288,098	2021-02-12 08:00	4,475,492	2022-02-03 08:00	4,448,653
2015-01-06 18:00	4,274,398	2016-12-16 19:00	4,250,044	2017-12-29 18:00	4,282,830	2018-01-15 19:00	4,283,117	2019-01-30 19:00	4,546,899	2020-01-16 21:00	4,279,281	2021-02-08 20:00	4,443,826	2022-01-07 19:00	4,426,258
2015-01-12 10:00	4,272,710	2016-12-18 19:00	4,244,298	2017-01-11 19:00	4,281,607	2018-01-15 10:00	4,282,728	2019-01-30 20:00	4,546,701	2020-02-12 09:00	4,278,801	2021-02-11 20:00	4,443,239	2022-01-20 09:00	4,423,665
2015-01-07 08:00	4,267,164	2016-12-15 18:00	4,240,284	2017-12-29 19:00	4,262,354	2018-02-12 09:00	4,277,403	2019-01-31 08:00	4,541,627	2020-02-12 19:00	4,278,549	2021-02-11 19:00	4,439,274	2022-02-23 08:00	4,409,216
2015-01-04 21:00	4,252,191	2016-12-12 18:00	4,228,958	2017-01-13 18:00	4,261,301	2018-01-11 18:00	4,267,446	2019-01-29 09:00	4,517,987	2020-02-12 20:00	4,277,365	2021-02-12 10:00	4,438,823	2022-02-03 10:00	4,408,092
2015-01-05 18:00	4,244,712	2016-12-14 19:00	4,228,713	2017-01-13 11:00	4,257,208	2018-01-11 19:00	4,251,378	2019-01-31 10:00	4,511,897	2020-02-12 08:00	4,261,901	2021-02-08 18:00	4,429,751	2022-02-22 08:00	4,406,977
2015-01-12 18:00	4,237,721	2016-12-14 08:00	4,209,495	2017-12-30 18:00	4,245,727	2018-01-15 20:00	4,248,712	2019-01-30 21:00	4,502,404	2020-02-12 21:00	4,261,122	2021-02-11 10:00	4,427,759	2022-02-24 08:00	4,401,073
2015-01-06 20:00	4,237,534	2016-12-16 20:00	4,207,696	2017-01-12 21:00	4,240,150	2018-01-11 20:00	4,248,545	2019-01-30 10:00	4,496,478	2020-01-15 19:00	4,255,106	2021-02-08 10:00	4,412,812	2022-01-07 11:00	4,396,456
2015-01-12 19:00	4,236,017	2016-12-17 20:00	4,204,328	2017-01-04 18:00	4,236,356	2018-02-09 08:00	4,233,554	2019-01-30 18:00	4,480,071	2020-01-15 18:00	4,251,747	2021-02-10 09:00	4,406,060	2022-01-07 08:00	4,393,673
2015-01-05 09:00	4,228,719	2016-12-15 19:00	4,202,278	2017-01-11 20:00	4,234,210	2018-01-15 11:00	4,226,442	2019-01-29 08:00	4,478,763	2020-02-13 09:00	4,246,321	2021-02-10 08:00	4,395,592	2022-02-22 09:00	4,389,778
2015-02-19 08:00	4,227,299	2016-12-18 20:00	4,192,235	2017-01-11 09:00	4,233,179	2018-01-12 19:00	4,222,015	2019-01-29 10:00	4,452,036	2020-01-16 17:00	4,232,960	2021-02-11 21:00	4,392,290	2022-01-06 18:00	4,387,270
2015-01-07 18:00	4,217,962	2016-12-14 20:00	4,191,512	2017-01-13 19:00	4,220,059	2018-01-12 18:00	4,221,247	2019-01-29 22:00	4,437,709	2020-02-19 08:00	4,230,397	2021-02-09 08:00	4,392,223	2022-01-05 18:00	4,383,990
2015-01-05 08:00	4,209,991	2016-12-12 19:00	4,190,084	2017-12-30 19:00	4,219,434	2018-01-11 21:00	4,220,076	2019-01-31 11:00	4,419,219	2020-01-16 11:00	4,226,281	2021-12-29 18:00	4,386,026	2022-01-25 09:00	4,379,624
2015-01-06 21:00	4,207,008	2016-12-14 09:00	4,179,560	2017-12-27 09:00	4,212,938	2018-02-09 09:00	4,214,231	2019-01-25 09:00	4,400,751	2020-01-15 20:00	4,221,215	2021-02-08 21:00	4,378,010	2022-02-17 09:00	4,374,900
2015-01-07 10:00	4,200,884	2016-12-17 09:00	4,178,042	2017-12-29 20:00	4,207,931	2018-01-15 21:00	4,204,175	2019-01-30 22:00	4,390,816	2020-02-19 09:00	4,190,447	2021-02-09 09:00	4,373,384	2022-01-07 16:00	4,369,422
2015-01-05 19:00	4,199,054	2016-12-17 17:00	4,168,058	2017-01-11 21:00	4,206,340	2018-01-04 18:00	4,200,434	2019-01-30 07:00	4,376,150	2020-01-08 09:00	4,184,271	2021-02-11 18:00	4,367,407	2022-02-04 09:00	4,358,212
2015-01-08 18:00	4,198,943	2016-12-16 21:00	4,167,368	2017-12-27 10:00	4,206,275	2018-01-16 09:00	4,199,922	2019-01-30 11:00	4,374,677	2020-02-07 08:00	4,182,633	2021-01-27 09:00	4,366,069	2022-01-20 08:00	4,357,673
2015-01-12 20:00	4,197,944	2016-12-18 17:00	4,166,379	2017-01-05 18:00	4,204,321	2018-01-05 09:00	4,196,367	2019-01-29 17:00	4,368,158	2020-02-07 09:00	4,181,593	2021-02-09 19:00	4,356,244	2022-01-06 19:00	4,354,592
2015-02-19 09:00	4,193,730	2016-12-17 21:00	4,163,960	2017-12-30 20:00	4,191,401	2018-01-04 19:00	4,182,952	2019-01-29 11:00	4,367,313	2020-02-12 18:00	4,177,538	2021-12-31 18:00	4,354,020	2022-01-25 08:00	4,352,958
2015-01-08 19:00	4,180,039	2016-12-13 18:00	4,162,927	2017-01-03 18:00	4,190,125	2018-01-12 20:00	4,181,464	2019-01-31 07:00	4,366,704	2020-01-16 22:00	4,174,937	2021-01-26 09:00	4,350,293	2022-02-23 09:00	4,350,682
2015-01-04 22:00	4,177,688	2016-12-17 10:00	4,161,188	2017-01-04 19:00	4,187,302	2018-01-04 09:00	4,180,876	2019-01-31 19:00	4,358,954	2020-01-15 21:00	4,173,497	2021-02-10 19:00	4,349,502	2022-01-10 18:00	4,350,011
2015-02-18 08:00	4,175,914	2016-12-12 20:00	4,152,107	2017-01-05 19:00	4,185,801	2018-02-01 09:00	4,175,802	2019-01-25 08:00	4,355,281	2020-01-16 07:00	4,172,747	2021-12-29 19:00	4,344,641	2022-02-03 18:00	4,347,542
2015-01-07 19:00	4,174,514	2016-12-13 09:00	4,148,581	2017-12-27 18:00	4,185,790	2018-01-16 08:00	4,171,159	2019-01-18 09:00	4,349,425	2020-01-17 09:00	4,171,335	2021-02-10 20:00	4,344,583	2022-01-07 12:00	4,338,943
2015-01-05 10:00	4,172,799	2016-12-14 21:00	4,146,664	2017-12-29 21:00	4,177,827	2018-02-08 08:00	4,166,953	2019-01-31 18:00	4,338,903	2020-02-12 22:00	4,165,654	2021-02-11 07:00	4,342,793	2022-01-07 20:00	4,337,424
2015-01-08 20:00	4,157,110	2016-12-16 17:00	4,146,286	2017-01-12 22:00	4,176,086	2018-02-01 08:00	4,164,973	2019-02-07 19:00	4,336,408	2020-02-12 10:00	4,161,319	2021-02-08 11:00	4,341,137	2022-01-06 20:00	4,336,983
2015-01-09 09:00	4,148,553	2016-12-15 20:00	4,146,049	2017-01-13 07:00	4,173,242	2018-01-03 18:00	4,164,085	2019-01-29 12:00	4,321,139	2020-01-15 09:00	4,154,840	2021-02-12 19:00	4,335,345	2022-02-03 19:00	4,335,890
2015-01-12 11:00	4,145,711	2016-12-18 21:00	4,144,918	2017-01-03 19:00	4,168,860	2018-01-05 18:00	4,163,772	2019-01-31 12:00	4,314,354	2020-01-08 08:00	4,153,999	2021-12-31 19:00	4,332,149	2022-02-24 09:00	4,333,652
2015-01-12 21:00	4,137,437	2016-12-13 08:00	4,143,114	2017-01-11 08:00	4,166,313	2018-01-31 19:00	4,163,185	2019-01-31 20:00	4,307,925	2020-01-08 18:00	4,153,817	2021-01-27 08:00	4,318,048	2022-02-02 19:00	4,331,634
2015-01-07 20:00	4,135,068	2016-12-15 10:00	4,136,102	2017-01-12 09:00	4,164,659	2018-01-12 11:00	4,161,384	2019-01-25 10:00	4,305,904	2020-01-20 09:00	4,147,656	2021-02-09 20:00	4,317,656	2022-01-06 21:00	4,328,016
2015-01-05 20:00	4,131,315	2016-12-17 22:00	4,131,040	2017-01-13 14:00	4,161,627	2018-01-11 09:00	4,160,458	2019-02-07 20:00	4,293,965	2020-01-08 10:00	4,133,558	2021-02-10 21:00	4,316,140	2022-01-05 19:00	4,327,382
2015-01-03 18:00	4,130,103	2016-12-16 09:00	4,121,073	2017-01-13 20:00	4,158,052	2018-01-04 20:00	4,158,559	2019-01-29 13:00	4,289,396	2020-01-10 09:00	4,132,902	2021-02-07 19:00	4,315,402	2022-12-07 18:00	4,318,138
2015-01-13 09:00	4,126,678	2016-12-13 19:00	4,117,206	2017-01-13 13:00	4,155,841	2018-01-04 10:00	4,158,042	2019-01-18 10:00	4,288,117	2020-01-15 22:00	4,121,405	2021-02-12 11:00	4,314,886	2022-01-07 15:00	4,318,129
2015-01-06 22:00	4,125,047	2016-12-14 17:00	4,104,068	2017-12-27 19:00	4,154,553	2018-01-05 10:00	4,157,969	2019-01-29 23:00	4,286,585	2020-01-16 12:00	4,119,453	2021-02-12 20:00	4,312,673	2022-01-10 09:00	4,317,557
2015-01-09 08:00	4,121,092	2016-12-15 17:00	4,096,751	2017-12-30 21:00	4,151,506	2018-02-06 08:00	4,150,817	2019-02-04 19:00	4,286,531	2020-01-16 16:00	4,116,045	2021-02-08 07:00	4,310,799	2022-01-20 10:00	4,317,221
2015-01-08 21:00	4,116,673	2016-12-14 10:00	4,095,304	2017-01-04 09:00	4,146,620	2018-01-15 22:00	4,148,368	2019-01-18 08:00	4,274,568	2020-01-15 10:00	4,115,994	2021-02-13 09:00	4,305,863	2022-02-02 20:00	4,315,042
2015-01-05 21:00	4,111,609	2016-12-12 17:00	4,092,120	2017-01-04 20:00	4,146,004	2018-01-15 17:00	4,146,634	2019-12-10 09:00	4,263,099	2020-01-20 08:00	4,113,752	2021-02-09 18:00	4,305,024	2022-02-03 11:00	4,314,466
2015-02-12 09:00	4,111,426	2016-12-18 10:00	4,091,144	2017-01-03 20:00	4,145,901	2018-01-16 10:00	4,146,504	2019-01-29 14:00	4,261,358	2020-01-17 08:00	4,112,000	2021-02-11 22:00	4,303,294	2022-01-07 13:00	4,311,222
2015-01-04 17:00	4,111,351	2016-12-15 21:00	4,090,559	2017-01-10 18:00	4,144,791	2018-01-31 18:00	4,144,486	2019-02-07 18:00	4,259,468	2020-01-15 08:00	4,108,865	2021-02-12 07:00	4,301,650	2022-01-19 19:00	4,309,308
2015-01-13 08:00	4,111,203	2016-12-17 11:00	4,084,422	2017-01-10 19:00	4,139,808	2018-02-07 08:00	4,141,559	2019-02-04 18:00	4,255,714	2020-01-17 10:00	4,108,630	2021-01-26 08:00	4,295,829	2022-01-25 19:00	4,309,129
2015-02-12 08:00	4,104,675	2016-12-16 08:00	4,084,224	2017-01-09 09:00	4,139,015	2018-01-11 22:00	4,140,779	2019-01-30 12:00	4,251,760	2020-01-08 19:00	4,103,562	2021-02-11 11:00	4,293,409	2022-01-05 11:00	4,306,754
2015-01-07 11:00	4,103,558	2016-12-13 20:00	4,083,268	2017-01-13 12:00	4,138,340	2018-01-12 21:00	4,136,075	2019-01-31 17:00	4,251,373	2020-02-14 09:00	4,097,429	2021-02-06 19:00	4,291,740	2022-01-19 18:00	4,301,725
2015-01-06 17:00	4,103,186	2016-12-16 22:00	4,082,813	2017-01-05 20:00	4,136,001	2018-02-06 09:00	4,136,033	2019-01-31 21:00	4,244,435	2020-02-14 08:00	4,093,699	2021-12-29 20:00	4,291,369	2022-02-04 08:00	4,299,762
2015-01-05 11:00	4,101,023	2016-12-10 18:00	4,080,597	2017-01-09 18:00	4,134,658	2018-02-12 10:00	4,134,757	2019-01-24 19:00	4,242,672	2020-01-10 18:00	4,091,612	2021-02-10 10:00	4,284,830	2022-01-09 18:00	4,298,477
2015-02-17 20:00	4,098,855	2016-12-18 09:00	4,079,065	2017-12-29 17:00	4,132,036	2018-02-01 19:00	4,134,579	2019-01-29 16:00	4,242,239	2020-02-13 10:00	4,091,500	2021-12-30 18:00	4,284,406	2022-01-06 10:00	4,294,673

Diff Top to 50th	248,887		246,939		320,246		267,979		347,765		333,878		267,809		224,608
Percentage	5.72%		5.71%		7.19%		6.09%		7.58%		7.54%		5.88%		4.97%