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November 2, 2026

Via Electronic Mail and Courier

Newfoundland and Labrador Board of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Mr. Mike McNiven, Board Secretary

Dear Mr. McNiven:

Re: Newfoundland and Labrador Hydro 2026 General Rate Application
Pre-Filed Testimony on behalf of the Island Industrial Customer Group

On behalf of the Island Industrial Customer Group, please find enclosed for filing the Pre-Filed Testimony of Patrick Bowman in respect of the above-noted Application.

We trust the above and enclosed to be in order.

Yours truly,

Stewart McKelvey

Dana Constantine

Dana Constantine

DC/bm

Enclosures
c.
Glen G. Seaborn
Denis J. Fleming

Public Utilities Board
Jacqui Glynn
Ryan Oake
Mike McNiven
Colleen Jones
Board Record
Michael Collins

Newfoundland and Labrador Hydro
Shirley Walsh
Daniel Simmons
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Consumer Advocate General

Labrador Interconnected Group
Nicholas E. Kennedy, Olthius Kleer Townshed LLP

Iron Ore Company of Canada
Gregory A. C. Moores, Stewart McKelvey

PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO NEWFOUNDLAND HYDRO
2026 GENERAL RATE APPLICATION

Submitted to:

The Newfoundland and Labrador Board of Commissioners of Public Utilities

on behalf of

The Island Industrial Customer Group

Prepared by:

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Nov 2, 2026

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1.0 INTRODUCTION

This Pre-filed Testimony has been prepared by Mr. Patrick Bowman of Bowman Economic Consulting Inc. with the support of Mr. Andrew McLaren of R.A. McLaren Consulting Inc., for the Island Industrial Customers Group (**"IIC Group"**)

The IIC Group includes four large industrial companies operating on the island during the test year. These companies are:

- Corner Brook Pulp and Paper Limited (**"CBPP"**);
- Braya Renewable Fuels (Newfoundland) LP (**"Braya"**);
- Marathon Gold Corporation (**"Marathon"**); and
- Vale Newfoundland and Labrador Limited ("**Vale"**)

These customers make up a substantial portion of the full industrial customer complement operating on the Island (**"IIC"**).

This testimony reviews and assesses the Newfoundland and Labrador Hydro (**"Hydro"** or **"NLH"**) 2026 General Rate Application (**"GRA"** or the "**Application**") filed with the Newfoundland and Labrador Board of Commissioners of Public Utilities (**"PUB"** or **"Board"**) on May 27, 2026, and related materials. The GRA covers the 2027 Test Year, with anticipated annual adjustment mechanisms providing for rate changes through 2030 (as opposed to further GRAs) with the next Test Year anticipated to be 2031.[1]

With respect to the testimony contained herein, Mr. Bowman notes the material was prepared by him or under his direction, and acknowledges 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 setting electric utility revenue requirements, cost allocation and rate design.
- 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.

Mr. Bowman has provided evidence in every Newfoundland Hydro GRA since 2003, and has participated in other proceedings related to Rate Mitigation (2019), Cost of Service (2018 and 2026), Electrification,

[1] Application, Volume I, page 5.21; pdf page 164 of 464.

Conservation and Demand Management (2021), Depreciation (2012), and the Rate Stabilization Plan (2010), as well as the 2001 GRA (where he supported the intervention but did not provide evidence).

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 utility regulation experience includes work for each of utilities, large industrial customers, small commercial and residential customers, wholesale customers, and regulators.

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Specific recommendations contained in this testimony are as follows:

Recommendation 1: Hydro's Proposal to classify cost components in the Long-Term Supply Cost Variance Deferral Account, consistent with their classification in the most recent GRA Cost of Service study, is appropriate and should be approved.

Recommendation 2: Capacity-related balances in the Long-Term Supply Cost Variance Deferral Account should be allocated at year-end on the measured class share of Coincident Peak for the year.

Recommendation 3: Allocation of demand-related costs should reflect class peaks consistent with a P90 load condition, consistent with Hydro's need to plan for weather conditions more extreme than average.

Recommendation 4: Holyrood plant-related costs should be classified 100% to demand.

Recommendation 5: Holyrood fuel should be classified consistent with Holyrood plant costs, reflecting the cost causation link with the reason these costs are incurred.

Recommendation 6: Hydro's proposal to adopt a 64 MW hydraulic generation credit for Newfoundland Power ("NP") for generation and transmission purposes is appropriate and should be adopted.

Recommendation 7: The proposed 39.3 MW thermal generation credit to NP in the Cost of Service study should be rejected, as well as the 12 MW curtailable load credit.

Recommendation 8: A revised approach to capacity resource acquisition should be implemented, based on fair and transparent treatment of all dispatchable and periodic customer resources (thermal generation and curtailable).

Recommendation 9: For the purposes of the 2027 Test Year, a thermal generation credit for NP should be premised on a $3.921 million payment to NP for the services of its thermal generation, and a payment of no more than $336,000 to NP for the services of its curtailable program based on 12 MW of capacity. These costs should be part of Hydro's revenue requirement and included in Hydro's Cost of Service allocations based on a 100% demand classification.

Recommendation 10: Dispatchable capacity related credits in the COS study (thermal generation or curtailable) should not be considered an adjustment to transmission cost allocation.

Recommendation 11: Hydro's proposal to use the updated ELCC values to classify wind generation between demand and energy should be approved.

Recommendation 12: Hydro's proposed changes to the IIC rate design should not be approved. Instead, the Board should direct Hydro to participate in a process with the IICs to develop a new proposal focused on potentially improving both energy and demand price signals across both firm and non-firm energy, as well as support for electrification or self-generation.

Recommendation 13: In the event the Board decides it will approve the proposed rate design, the Board should require modifications, as outlined in this evidence, to maintain demand price signals and reduce adverse impacts on customers who currently have a high load factor in winter months.

Recommendation 14: The additions at the Western Avalon Terminal Station completed since the 2019 Test Year should not be specifically assigned to Vale unless Hydro can establish that:

1. **The assets are directly and solely related to service to Vale via TL208;**
2. **The addition of the assets was driven primarily by Vale's service requirements; and,**
3. **The assets are distinct from the ring bus assets indicated to be a common asset in the 2018 SAC Review.**

Recommendation 15: For the next GRA, Hydro should consider the physical arrangement and commercial nature of Linde's operations in order to determine if the TL 208 and Long Harbour substation assets should now be considered common, on the basis of the assets serving multiple distinct and commercially independent customers.

2.0 OVERVIEW OF THE ISLAND INTERCONNECTED SYSTEM AND SUPPLY CHANGES SINCE THE LAST GRA

The Island Interconnected System (**"IIS"**) has seen material changes since the GRAs held for the 2019 Test Year (the **"2017 GRA"**), and the 2015 Test Year (the **"Amended 2013 GRA"**). Most notable among these changes is the interconnection of the island system with Labrador (the Labrador-Island Link, or **"LIL"**), and the initiation of supply from the Muskrat Falls generation station.

Prior to interconnection with Labrador, the most material cost drivers and instability in rates on the island system were related to large quantities of fuel required at the Holyrood Thermal Generating Station (**"Holyrood"** or **"TGS"**). Holyrood was a significant producer of energy (approximately 1,600 GW.h for 2015 Test Year, or more than 20% of island supply)[2] and functioned as the effective marginal cost for all energy consumption throughout the year. Even in the months when Holyrood was not operating, added energy generation requirements would lead to use of stored water for hydraulic generation, which necessitated additional Holyrood energy output later in the year.

For the 2027 Test Year, Holyrood is no longer dispatched for energy reasons under average water conditions[3], and "its current role is primarily to provide system reliability and backup generation until new resources are commissioned."[4] This capacity-related role is expected to end by 2030, when the generating role for Holyrood terminates.

Looking forward, the utility industry has been facing material changes in availability of and necessity for power resources. A confluence of factors has shifted Canadian utility focus towards the challenges of meeting peak winter capacity. The factors creating this challenge include: (a) electrification of load, particularly of heating which drives winter peak, (b) decarbonization, which tends to make easily-built peaking resources (e.g. combustion turbines, or **"CTs"**) less attractive, (c) the expansion of computing requirements worldwide, which has tended to make CTs more costly and less available, and (d) declining costs for renewable generation such as wind, which makes energy easier to acquire and lower cost than in past periods, but does not generally satisfy capacity requirements to the same extent as dispatchable generation.

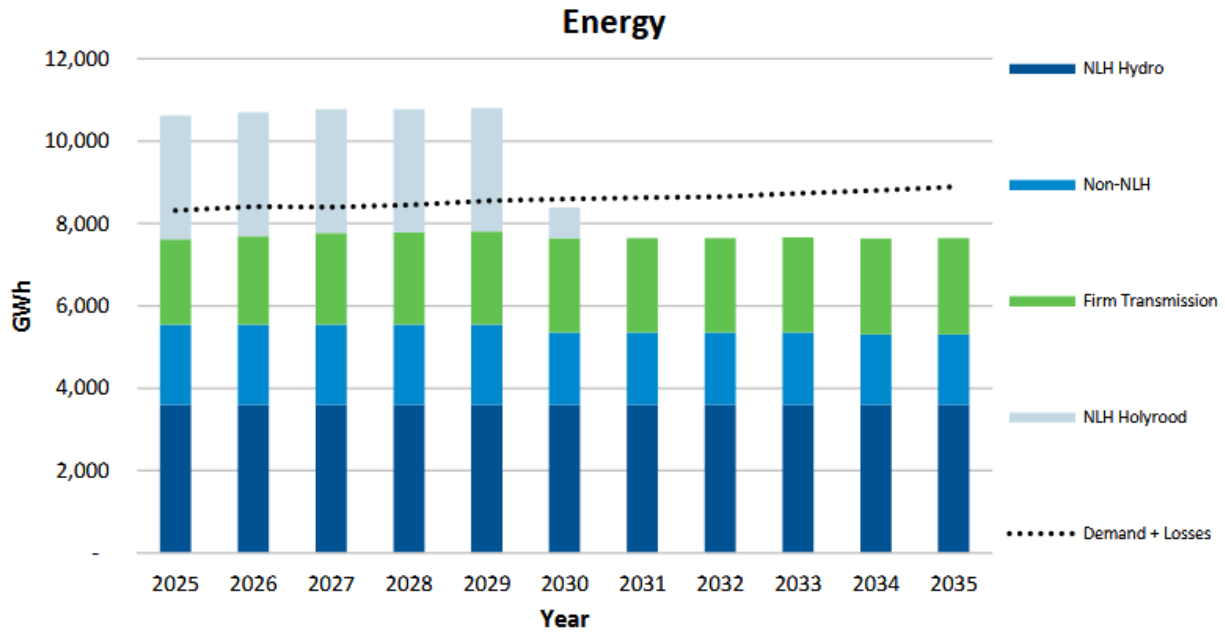
[2] 2013 Amended GRA Application Volume 1, Schedule V, page 6, pdf page 235 of 367.
[3] 2013 Amended GRA Application Volume 1, Schedule V, page 7, pdf page 236 of 367. As discussed below, it is not clear that Holyrood is in fact required for energy reasons in drought conditions, considering the updated UFLS study, and the potential for non-firm imports.
[4] Application, Volume 2, Exhibit 4, page 6; pdf page 96 of 892.

Hydro has emphasized in its Reliability and Resource Adequacy (**"RRA"**) process that it is primarily focused on a "minimum investment required" strategy.[5] This strategy reflects minimum assumptions regarding electrification, and slow decarbonization.

Under this strategy, there is a need for imminent capacity investment in both CTs and Bay D'Espoir unit 8 (**"BDE 8"**) as peaking resources.[6]

With respect to energy, as shown in the following Hydro-produced figure from 2014, Hydro is forecasting limited shortfalls starting in 2030 when Holyrood generation is scheduled to be retired:[7]

Figure 2.1: Island Firm Energy Requirements under Slow Decarbonization Scenario



While the above Figure 2.1 shows that Hydro is forecasting energy shortfalls once Holyrood is retired, this is not a robust conclusion. Rather, any consideration of Hydro's forecast energy shortfall must take into account the following factors:

[5] NLH 2024 Resource Adequacy Plan Update, page 33. http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%202024%20Resource%20Adequacy%20Plan%20-%20REVISION%202%20-%20REDACTED%20-%202024-08-26.PDF pdf page 61 of 673.

[6] NLH Build Application BDE Unit 8 and Avalon CT. http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/app/From%20NLH%20-%20Application%20for%20Capital%20Expenditures%20for%20the%20Purchase%20and%20Installation%20of%20Bay%20d%E2%80%99Espoir%20Unit%208%20and%20Avalon%20Combustion%20Turbine%20-%20Redacted%20-%202025-03-21%20-%20UPDATED%20-%202025-05-09.PDF

[7] Ibid, page 13, pdf page 252 of 762.

1) Figure 2.1 assumes the worst drought conditions for hydro generation. Under average conditions, the available supply exceeds 9,000 GW.h and there are no shortfalls.[8]

2) Figure 2.1 assumes no thermal generation other than Holyrood would be dispatched or dispatchable for energy generation.

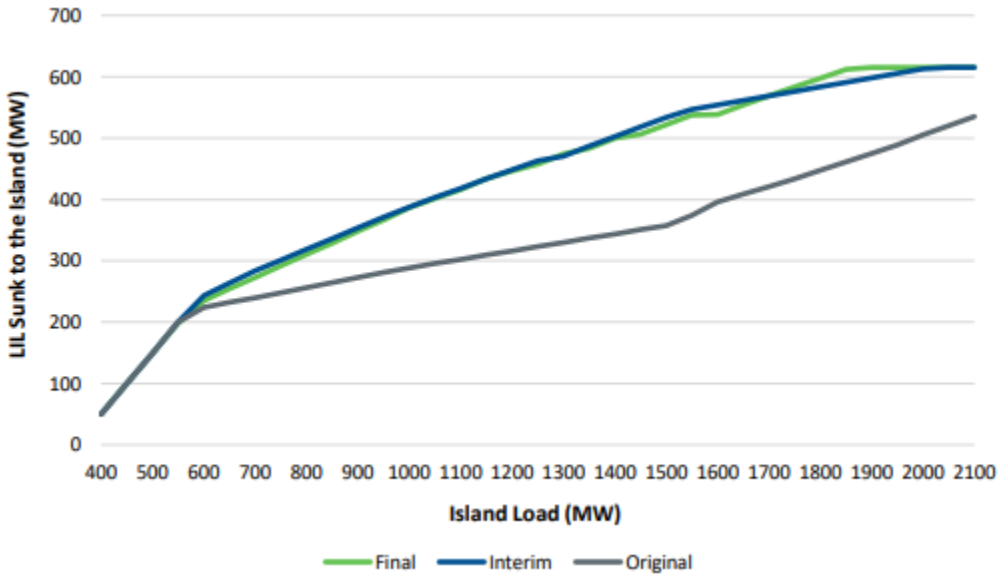
3) Figure 2.1 assumes termination of existing PPAs for ongoing wind assets that Hydro currently purchases[9] (totalling approximately 180 GW.h).[10] However, there is no information that the facilities are at end of life, simply at end of the PPA.[11]

4) Figure 2.1 includes no imports over the Maritime Link, despite Hydro noting: "The Maritime Link enables the delivery of exports to the North American market, allows for imports to support Island Interconnected System reliability and reservoir optimization, when available, and has other system benefits, including reduced under-frequency load shedding."[12] While imports may be only available as non-firm energy, it is an extreme assumption to conclude that none will be available in any of the 8760 hours in a year.

More significantly, since Figure 2.1 was prepared in 2024, Hydro has completed a review of Under Frequency Load Shedding (**"UFLS"**) on the island system that will increase the availability of energy from Labrador materially. In the Q2 2026 Semi Annual Report on the RRA process, Hydro noted it had completed the "Final Lower Churchill Project Operational Study" that provides a "Final UFLS scheme, which will reduce the firm energy deficit that was presented in the 2025 Build Application by approximately 450–500 GWh."[13] As demonstrated in Figure 2.2 below, at many Island load levels, the new scheme permits imports that are more than 100 MW higher than had been modelled in the 2024 analysis:

[8] RRAS Technical Conference Issues 5 and 6 presentation, pdf page 57 of 106.
[9] Ibid, page 14, pdf page 252 of 762.
[10] CA-NLH-150
[11] PUB-NLH-166.
[12] Application, Volume 1, page 1.9.
[13] RRA Study Review – Semi Annual Update for the Second Quarter of 2026. http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Q2%202026%20Semi-Annual%20Report%20-%202026-06-30.PDF, page 5, pdf page 5 of 471.

Figure 2.2: Updated LIL to Island Load Relationship Based on Final UFLS Scheme



The Semi-Annual report also noted that "Hydro is studying the use of Battery Energy Storage Systems (**"BESS"**) as frequency support, which may allow for additional energy to be brought to the Island via the Labrador-Island Link."[14]

While Hydro continues to complete an Expression of Interest process for additional generation such as wind, the above changes indicate the system is facing very limited energy shortfalls, if any, into the 2030s even with Holyrood retirement.[15] It is important to note that this limited (or zero) **energy** shortfall does not indicate the currently proposed capacity resources (Avalon CT and BDE 8) are not required. Capacity shortfalls still persist on the island system, and the above considerations do not materially affect the significant **capacity** shortfalls faced by Hydro.

Finally, the above supply conditions indicate a system that (i) has a high degree of potential for adding island loads that are non-firm or interruptible, and (ii) can maximize the value of curtailable or capacity assistance loads.

This combination of resource drivers (incentives to add non-firm loads, and incentive to reduce demand peaks) reflects that energy is typically in surplus in any non-drought year. It also reflects that the incremental cost for energy is linked to exports whose price can vary widely, and can include low prices in many hours. At the same time, as capacity is in short supply, committing to firm loads on the Island is not ideal. However, non-firm loads do not exacerbate capacity issues. For the purposes of economic

[14] Ibid, page 2, footnote 7, pdf page 2 of 471.
[15] Ibid, page 2, pdf page 2 of 471.

development and local efficient use of resources, domestic use of non-firm power should be considered a priority over exporting this product.

3.0 LONG-TERM SUPPLY COST VARIANCE DEFERRAL ACCOUNT

Hydro is proposing to establish a new deferral account called the Long-Term Supply Cost Variance Deferral Account (**"LTSCVDA"**).

The account tracks variances in supply costs as compared to the previous GRA Test Year. In principle the account mirrors the types of protection that Hydro has benefitted from in the past, through the 2021 vintage Supply Cost Variance Deferral Account, and the Rate Stabilization Plan before that.

Unlike the 2021 Supply Cost Deferral Account, the new LTSCVDA now includes proposed allocation methods between the classes. Hydro proposes that variances in the costs for individual items (e.g., purchases, exports) mirror the treatment of the original cost items in the 2027 Test Year Cost of Service (**"COS"**) study.[16]

Hydro reviewed alternative allocation approaches, such as based on an energy-only allocator.[17] However, as noted by Hydro, this results in a poor matching between the basis for allocating a given cost item in a GRA, and allocating variances in the same cost item after a GRA.[18] Such conflict is not only inaccurate, but it could also result in an incentive for gaming among the parties. For example, a party could seek to set GRA estimates at a level higher or lower than would result from a proper GRA forecast, knowing that the eventual deferral accounting will leads to credits allocated in a different manner which would be beneficial to their class.

For example, if the LTSCVDA were allocated 100% on energy, industrial customers may benefit if a factor like export revenue forecasts are set low in the GRA, which would lead to higher net costs for both demand and energy in its 2026 and 2027 GRA. But once the future LTSCVDA was taken into account, customers would anticipate a credit from higher-than forecast export revenues, which will be refunded back to customer based 100% on energy use. As industrial customers tend to make up a relatively larger share of energy than wholesale loads, industrial customers would benefit from this type of scenario.

Having the LTSCVDA and GRA COS methods match ensures such outcomes do not occur.

Recommendation 1: Hydro's Proposal to classify cost components in the Long-Term Supply Cost Variance Deferral Account, consistent with their classification in the most recent GRA COS study, is appropriate and should be approved.

[16] Application, Volume 1, page 5.24; pdf page 167 of 464.
[17] Application, Volume I, section 5.7.2; pdf page 166 of 464.
[18] Application, Volume I, page 5.24; pdf page 167 of 464.

Hydro's description of the allocation of LTSCVDA balances in respect of energy appears to match longstanding practice with similar accounts.

With respect to demand allocation, Hydro proposes an approach that has monthly allocations: "derived from year-to-date kW for Utility Firm invoiced monthly billing demand, Industrial Firm maximum invoiced demand multiplied by the year-to-date months, and Rural Island Interconnected maximum peak demand multiplied by the year-to-date months"[19]

This approach does not appear to be consistent with the GRA, which allocates demand-related amounts based on the annual 1 CP. Hydro acknowledges this in response to RFIs:[20]

> [Hydro] proposed actual billing demands since it provides a reasonable method to allocate demand costs with an allocator based on readily available information that is easily verifiable, similar to an energy allocator for the current year. It is preferred over the test year coincident peak demand allocations because it captures changes in demand between test years which could drive variances in demand related costs. Hydro recognizes that the use of a coincident peak allocator for the current year would be consistent with the Cost of Service.

The above response does not appear to address why Hydro concludes that a coincident peak allocator (consistent with the COS) would not also "capture changes in demand between test years which could drive variances in demand related costs". In short, the basis for Hydro's proposed allocation as preferred over an annual 1 CP appears flawed. Also, billing demand could well be skewed by a mix of varying seasonal peak levels that are not directly tied to the winter peak cost driver. In short, measuring changes in demand that could drive variances in demand-related costs is better achieved by using annual 1 CP than a mix of monthly billing demands.

Recognizing that some form of interim monthly allocation is required in order to practically implement a demand-allocation, the Hydro approach may be merited on an interim intra-year basis. However, final year-end allocation adjustments should be established based on an appropriate measure of annual 1 CP, not a sum of invoiced monthly billing demand,

Recommendation 2: Capacity-related balances in the Long-Term Supply Cost Variance Deferral Account should be allocated at year-end on the measured class share of Coincident Peak for the year.

[19] Application, Volume 1, page 5.25; pdf page 168 of 464.
[20] PUB-NLH-086 (a).

4.0 COST ALLOCATION

4.1 OVERVIEW OF COST ALLOCATION METHODS

The use of COS analysis in Newfoundland and Labrador is appropriately premised on the principle of cost causation.[21] Costs should be allocated to the customer classes that cause the cost to be incurred.

Hydro's COS methodology was last reviewed as part of its 2018-19 COS methodology application, that resulted in a 2019 settlement agreement approved by the Board. This 2019 settlement agreement finalized the majority of the issues in dispute, and left a short list of issues to further study at a later date (then anticipated to be the next GRA).[22] The 2019 settlement agreement included the following provision:

> The Parties agree that the Cost of Service Methodology approved by the Board in this Cost of Service Methodology Application shall be the accepted methodology for use in the first General Rate Application filed to address recovery of Muskrat Falls Project costs upon full commissioning, except for any particular issues identified in this Settlement Agreement for further review in the GRA, after which a Cost of Service Methodology Review may be conducted upon request of any of the Parties and approval by the Board for such review.[23]

Hydro's 2026 GRA is the first GRA since the 2019 COS settlement, and therefore the first time the approved changes to the COS methods have been reflected in a GRA. Method changes from the 2019 settlement agreement that are implemented in the COS studies in the current GRA include the following:

1. The functionalization of power purchase costs resulting from the Muskrat Falls Power Purchase Agreement (**"PPA"**) and the Transmission Funding Agreement as generation;
2. No change to functionalization of Hydro's existing generation and transmission assets, with the exception of:
    a. The functionalization of Transmission Lines TL234 and TL263 as transmission; and
    b. The functionalization of Holyrood TGS Unit 3 as transmission after the unit is permanently converted into the role of synchronous condenser;
3. The functionalization of net export revenues as generation, in the same manner as the functionalization of the Muskrat Falls Project costs;
4. The classification between demand and energy for the power purchase costs resulting from the Muskrat Falls PPA and the Transmission Funding Agreement is based on system load factor. This

[21] CA-NLH-131.
[22] Board Order P.U.37 (2019).
[23] Paragraph 7, 2019 Settlement Agreement included as Schedule A to Board Order P.U. 37 (2019).

is inclusive of the costs related to Muskrat Falls generation, the LIL, and the Labrador Transmission Assets.

5. Net export revenues are classified using the system load factor, in the same manner as the classification of the Muskrat Falls Project costs; and
6. Net export revenues are included in the COS to reduce the supply costs related to the Muskrat Falls Project (including Muskrat Falls generation, the LIL and the Labrador Transmission Assets) to be recovered through the rates of customers on the Island Interconnected System.[24]

The 2019 settlement agreement also provided for certain information to be filed in the next GRA including:

1. A report and review on Conservation and Demand Management (CDM) justified in whole or in part on demand savings; how demand related CDM is classified in other jurisdictions and options to establish a materiality threshold to establish if changes to approach are appropriate.
2. A report on 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 COS study appropriately reflect the contribution of different customer classes to the coincident peak used for planning purposes.
3. Results of Hydro's cost tracking for specifically assigned assets and feasibility of using actual expenses in the calculation of specifically assigned charges (**"SAC"**).
4. A report reviewing the calculation of the MW credit provided to NP to ensure its reasonableness.
5. A deferral account proposal for variations in net export revenues.[25]

In 2025, Hydro filed a COS methodology application that addressed the reports required by the 2019 settlement agreement and Board Order P.U.37(2019), along with other proposed methodology updates.[26] This resulted in a 2025 settlement agreement that addressed many of the proposed changes in the 2025 methodology application[27] with the exception of the following issues which the parties agreed to defer to the current GRA:

1. Classification of Holyrood TGS generation costs and fuel costs; and
2. The implementation of a 64 MW hydraulic generation credit for NP, with the process for the determination of the thermal generation credit to remain unchanged from past practice.[28]

[24] Page 6.2 line 23 through page 6.3 line 14 of Volume I of Hydro's 2026 GRA.
[25] Summarized from Page 4 line 42 through page 5 line 11 of Board Order P.U.37 (2019).
[26] These are summarized in section 6.2.1 of Volume I of Hydro's 2026 GRA.
[27] Settlement Agreement May 15, 2026
http://www.pub.nf.ca/applications/2026/NLH2025CostOfServiceMethodology/settlement/Settlement%20Agreement%20-%202026-05-15.pdf
[28] Summarized from Page 6.5 lines 17 through 20 of Volume I of NLH's 2026 GRA.

Hydro's GRA now includes requested approvals for three COS method changes:

1. Treatment of Holyrood generation costs and fuel costs;
2. NP Generation Credit; and
3. Classification of wind generation purchases.[29]

The net effect of the COS changes is a differential impact on the various IIS classes, such that, when applied with consistent mitigation assumptions, the island industrial class receives a relative rate reduction compared to the wholesale and retail classes. This is to be expected for a number of reasons:

1) The Island industrial class, consistent with most industrial customers in the utility industry, is a high load factor class. This means the class is relatively more responsible for costs considered to be energy-related, and relatively less responsible for costs considered to be peak capacity, or demand-related.

2) The previous GRA COS studies included significant supply from Holyrood, which was a mixed capacity and energy cost plant. The Holyrood capacity costs are primarily linked to the capital-related costs (depreciation, interest etc.) and the energy-related costs tied to both plant costs, but more so to fuel. As outlined in section 2, the evolution of costs on the IIS from 2019 Test Year to 2027 Test Year results in a reduction of Holyrood fuel requirements – the energy related portion of the costs - and replaces it with Labrador hydraulic generation (classified according to the system load factor). This causes a net relative decrease in energy cost (after mitigation) but less to capacity. The associated savings from retiring Holyrood plant, which would skew towards capacity, will not occur until 2030.

3) Load growth on IIS has primarily been in loads that peak in winter, which has resulted in more capacity driven investment and a lower system load factor. This shift is anticipated to continue, and will continue to drive investment in capacity-related costs (such as CTs).

As a result, the differential customer class effects are as anticipated. Further Hydro has appropriately modelled the following concepts:

1) Rate mitigation consistent with OC 2024-062, which targets 2.25% increases for retail customers related to Muskrat Falls, and mitigation to other customers that is "compatible with the Hydro Target Rate Increase". The COS applies rate mitigation such that the Muskrat Falls costs are effectively reduced to achieve the 2.25% target for NP wholesale rates, and a concurrent equal benefit for all other IIS classes.

[29] Sections 6.2.2; 6.2.3 and 6.3.1 of Volume I of NLH's 2026 GRA.

2) Targeting 100% revenue to cost ratios, prior to rural deficit reallocation, for both wholesale NP and for IIC. This is consistent with longstanding practice, and reflects appropriate links to cost causation, and of the *Electrical Power Control Act (1994)* prohibition against industrial customers subsidizing the rural deficit.[30]

The following sections provide discussion and recommendations related to the calculation of coincident peaks used in the COS methods, and the three methodology change approvals sought by Hydro. These items remain outstanding from the 2019 and 2025 settlement agreements.

4.2 COINCIDENT PEAK CALCULATION

In designing the system, Hydro applies varying standards for reliability, reserve margins, and sensitivity testing.

Among the items tested for capacity are the impacts of extreme winter conditions. This is referred to as the difference between P50 (normal conditions) and P90 (relatively extreme conditions not expected to be exceeded except in 10% of cases. There is no reasonable basis to accept a utility being able to only deliver reliable power when weather is consistent with a typical winter. Rather, utilities are expected to be able to supply power even in the face of a relatively extreme winter event. In other words, utility failures to deliver due to insufficient generation supply or transmission infrastructure should be very rare. Consistent with this principle, Hydro uses a target of no more than 2.8 hours per year for generation supply insufficiency on average (based on the industry standard measure of Loss of Load Hours, or LOLH), and plans transmission systems to meet extreme winter peaks.

In making its assessments of whether it has sufficient capacity, Hydro uses various assumptions about load and weather. Hydro indicates it uses P50 weather assumptions for deriving the peak used for allocation purposes in the COS.[31] However, for planning purposes, Hydro considers conditions that are worse than P50. On this issues, in the 2025 COS Methodology Application, Hydro states:[32]

> In recent years, Hydro began reporting a P90 forecast as a sensitivity load in its planning studies to assist in the assessment and reporting on forecast exposure. The P90 peak demand forecast reflects an associated increase in demand over an average, or P50, peak demand forecast resulting from instances of more

[30] *Electrical Power and Control Act (1994)*, section 3(a)(iv).
[31] PUB-NLH-007 (b).
[32] 2025 COS Methodology Application, Schedule 1, Attachment 2, page 4. http://www.pub.nf.ca/applications/2026/NLH2025CostOfServiceMethodology/app/From%20NLH%20-%20Application%20for%20Cost%20of%20Service%20Methodology%20-%202025-08-22.PDF pdf page 65 of 274.

> severe wind and/or cold temperatures. During P90 weather conditions, the peak demand will exceed the average (P50) demand level.
>
> As referenced in the Reliability and Resource Adequacy Study – 2022 Update, Hydro states that the Island Interconnected System capacity requirements are based on a P50 peak demand forecast. Hydro maintains that basing supply planning decisions on a P50 peak demand forecast, while continuing to assess and report to the Board of Commissioners of Public Utilities on forecast exposure under the P90 peak demand forecast, balances system reliability and investment cost at this time. Further, embedding load forecast uncertainty in the determination of planning reserve margin increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discreetly.

As outlined in the above quote, Hydro is clearly addressing load forecast uncertainty as part of generation planning. This can be done explicitly, by using a peak higher than P50 (e.g., P90) peak demand forecast, or implicitly by "embedding load forecast uncertainty in the determination of planning reserve margin".

Hydro also considers load forecast uncertainty in transmission planning (46 kV or higher, but less than 230 kV, which is planned by the Newfoundland and Labrador System Operator, or **"NLSO"**) [33], and indicates that the peak load forecasts for the IIS planning are based on P90.

The 2025 COS settlement provides as follows:[34]

> The Parties agree that the coincident peaks to be used in Hydro's Cost of Service Study filed in Hydro's upcoming GRA should reflect the contribution of the different customer classes to the coincident peak used for planning purposes.

As described above, the peaks used for planning purposes clearly include the risks of colder than average weather, in either an explicit input (transmission modelling and reporting, and generation reporting) or implicit input (generation modelling).

The degree of load forecast uncertainty is not small, and is a clear cost driver of capacity investment on the system, whether included explicitly or implicitly. In response to IIC-NLH-036(a), Hydro provided the following Table 4.1 indicating the difference between a P50 peak and a P90 peak:[35]

Table 4.1: Coincident Peak Allocation under a P50 and P90 Weather Forecast

[33] LAB-NLH-030 Attachment 1, page 3.
[34] 2025 COS settlement, item 13.
[35] IIC-NLH-036 (a).

	Non-Coincident Peak (MW)	Coincident Factor (%)	Coincident Peak (MW)	P90 Addition (MW)	Total P90 (MW)
Newfoundland Power	1450.3	99.44%	1,441.8	57.0	1,498.8
Island Industrial	91.3	86%	78.5	-	78.5
Hydro Rural	94.9	98%	93.0	3.0	96.0
Total Deliveries			**1,613.3**	**60.0**	**1,673.3**
Transmission Losses			70.4	70.4	70.4
System Electricity Requirement			**1,683.7**	**130.4**	**1,743.7**

As outlined in the above Table 4.1, industrial customers cause no material load forecast uncertainty associated with weather. But other classes, who rely on electricity frequently for space heating, do cause such effects and costs.

Hydro agreed to study the impacts of using a P50 versus P90 peak as part of the 2019 COS settlement agreement. In the 2025 COS Application, Hydro produced a report on the potential differences in each class's Coincidence Factors (**"CF"**) at peak times. A CF is a ratio between the peak a customer class achieves on its own (the Non-Coincident Peak, or **"NCP"**) and the peak it contributes to the overall system peak, which occurs at a different time (the Coincident Peak, or "**CP"**). The CF provides no information about variability in the NCPs themselves, as would be caused by adverse weather.

This CF study confirmed:[36]

> Newfoundland Power and Hydro Rural Island Interconnected ("Hydro Rural") loads are strongly correlated with weather, while the Industrial class does not show correlation.
>
> …
>
> This supports the production of a P90 sensitivity forecast for Newfoundland Power and Hydro Rural demand only.

Hydro's study only analyzes CFs and whether class coincidence factors vary between years with cold temperature versus others. It concludes "it is appropriate to use the same CFs when calculating P50 and

[36] 2025 COS Application, Schedule 1, Attachment 2, page 3-5. http://www.pub.nf.ca/applications/2026/NLH2025CostOfServiceMethodology/app/From%20NLH%20-%20Application%20for%20Cost%20of%20Service%20Methodology%20-%202025-08-22.PDF pdf page 65-67 of 274.

P90 system peaks and that no additional CFs are needed for the time of peak at this time"[37], which is a reasonable conclusion with respect to CFs.

However, Hydro's study makes no conclusion regarding the COS treatment of the specific impact of the fact that adverse weather causes an increase of 60 MW in the wholesale and rural load coincident peak loads.

Consistent with the need for Hydro to plan to meet load conditions of more extreme than average weather, it is appropriate to allocate demand-related costs on the basis of P90 peak loads, as shown in IIC-NLH-036 (a).

Recommendation 3: Allocation of demand-related costs should reflect class peaks consistent with a P90 load condition, consistent with Hydro's need to plan for weather conditions more extreme than average.

4.3 HOLYROOD GENERATION COST CLASSIFICATION

The classification of Holyrood plant costs to demand versus energy was addressed in the 2019 COS settlement agreement. Specifically, that agreement provided that classification of Holyrood "generation costs, excluding fuel, be based on a test year forecast capacity factor."[38] That agreement did not specify a classification for Holyrood fuel.[39]

In the 2025 COS application, Hydro sought approval that "classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor" and that "Holyrood TGS fuel costs be classified as 100% energy."[40] The 2025 COS application stated that: "…fuel costs related to Holyrood are currently classified as energy, approved by the Board in P.U. 30(2019)"[41] and indicated that the parties had agreed to this in the 2019 COS settlement. However, this is not supported by a review of the 2019 settlement agreement, which does not explicitly comment on Holyrood fuel classification.

Rather, the 2025 settlement explicitly did not reach agreement on the requests regarding Holyrood plant classification, nor Holyrood fuel classification.

[37] Ibid, page 13. Pdf page 76 of 274.
[38] 2019 COS settlement agreement, provision 20. http://www.pub.nf.ca/applications/2018/NLH2018CostofService/settlement/Settlement%20Agreement%20-%202019-10-04.PDF
[39] Hydro also notes this treatment was not approved in the 2019 COS settlement, in its Table 5-13 (Application, Volume 1, pdf page 167 of 464), where the basis for 100% energy classification of Holyrood fuel is linked to P.U. 30 (2019), which is the order from the previous GRA, and not P.U. 37 (2019) which is the later order from the 2018-19 COS proceeding.
[40] GRA Application, Volume I, section 6.2.2, page 6.7; pdf page 181 of 464.
[41] 2025 COS Application, page 13; pdf page 23 of 274.

It is apparent that the function of Holyrood in the 2027 Test Year does not reflect the factual situation underlying the 2018-19 COS review. At the time of that 2018-19 review, Hydro noted:

> Upon commissioning of the Muskrat Falls Project, supply cost payments to cover the cost of transmission and generation assets will commence under the Transmission Funding Agreement ("TFA") and Muskrat Falls Power Purchase Agreement ("PPA"), and the role of Holyrood as a generating station will be phased-out.

The 2018 application assumed "…that Holyrood generation would conclude in 2021" and provided forecasts of generation based on the premise that fuel costs in 2021 reflect only "generation at Holyrood to eliminate the fuel inventory through the provision of capacity and energy during the first quarter of 2021."[42]

Instead, Holyrood's role in generation has not been phased-out, though the role of Holyrood has materially changed from the provision of capacity and energy. In effect, for the 2027 Test Year, Holyrood is solely a capacity resource. However, Holyrood is an inferior resource for this role, as it is not responsive in terms of quick or dependable start-up. Instead, the unit must be operated continuously all winter in order to maintain its readiness for the capacity support role. As noted by Hydro:[43]

> Under normal operating conditions and average inflows, the energy injected into the system from Holyrood TGS production is a direct result of the reliability requirement. Therefore, the Holyrood TGS forecasted production, and therefore fuel consumption, in the 2027 Test Year is directly attributable to operating the units at minimum stable output for reliability purposes only.

The energy produced by Holyrood in the 2027 Test Year is not a particularly valuable economic product. The cost per kW.h is high (14.28 cents/kW.h at GRA fuel prices of $78/bbl[44], for fuel alone)[45] and the economic value over the period of operation (Oct 16 to March 31)[46], assuming the output is exported as excess supply, is forecast to vary from 2.991 cents/kW.h to 4.414 cents/kW.h.[47]

This gives rise to two fundamental questions regarding Holyrood generation cost classification:

[42] 2018 Cost of Service Methodology Review Report, page 19. http://www.pub.nf.ca/applications/2018/NLH2018CostofService/application/Application%20-%20Cost%20of%20Service%20Methodology%20-%202018-11-15.PDF pdf page 30 of 144.
[43] PUB-NLH-102 (c).
[44] Note that fuel prices in the first half of 2026 were $123/bbl, per PUB-NLH-034 (e).
[45] CA-NLH-159 (c).
[46] CA-NLH-159
[47] Application, Volume 1, Table 6-5, pdf page 190 of 464.

1) Does it remain reasonable to retain a Test Year capacity factor classification for Holyrood plant costs, notwithstanding the 2019 settlement agreement, due to a material change in facts?

2) Is Holyrood fuel cost consistent with a 100% energy classification?

The 2027 Test Year capacity factor is 11.16%.[48] Use of this capacity factor for classification reflects the terms of the 2019 settlement. This results in 11.16% of the plant costs (e.g., depreciation, return on equity) being classified as energy, with the remainder as demand. Given the plant is not considered a valuable energy-related resource in the 2027 Test Year, unlike during the negotiations of the 2019 settlement agreement, consideration should be given to classifying the plant as 100% capacity, consistent with other thermal resources such as the Hardwoods turbine, given no cost causative link between Holyrood plant costs and energy needs in the 2027 Test Year.

It should be noted that Holyrood may, at best, play a small role in low water conditions in producing energy, not just capacity. However, as outlined in section 2 of this evidence, this role only occurs under the most extreme low water conditions, and even in that condition, is unlikely to occur with the revised LIL import limits, with non-firm purchases over the Maritime Link, and with the wind PPA purchases still under contract as they are in 2027. Further, the 2027 Test Year COS study is prepared under normal water conditions. As a result, there is little to no basis to support an energy classification for Holyrood tied to low water conditions.

In further support of the classification of Holyrood plant costs at 100% demand, the present transition away from Holyrood is expected to be completed by the time of the next GRA, in 2031. At that time, 2 units of Holyrood are to be retired, with the third retained as a synchronous condenser classified 100% to capacity. Adopting a 100% capacity classification for the plant now is a move in line with the anticipated direction of the Holyrood classification by the next GRA.

No COS scenario has been run for the impacts of adopting a 100% demand classification for Holyrood plant. However, a scenario was provided in CA-NLH-152 Attachment 1 that adjusts the capacity ratio from 11.19% to 18.43%[49], or an increase of 7.24%. Assuming a linear impact tied to percentages in Holyrood classification, adopting a 100% demand classification, a reduction of 11.19% in the Holyrood classification factor would be -1.54 times the effect outlined in this response for a total impact as follows:

- No net impact on NP wholesale rates
- Island industrial customers – a reduction of $352,000, or 0.82% of total allocated costs.

[48] PUB-NLH-102 (a).
[49] The 18.43% capacity factor is the 5-year average from 2020-2024, prior to the current LIL operating parameters, so is not relevant to the 2027 Test Year.

- Labrador interconnected – a reduction of $2,000, or 0.01% of total allocated costs
- An increase in mitigation funding of $354,000

There is no impact on costs for any other class.

Given a revised classification of 100% demand appropriately reflects the role and function of Holyrood in the Test Years, and is consistent with other capacity-related resources on the island system, the Holyrood plant-related costs should be classified 100% to demand.

Recommendation 4: Holyrood plant-related costs should be classified 100% to demand.

With respect to the fuel consumed at Holyrood, the present recommended classification from Hydro is to classify fuel as 100% energy. This contrasts with the 100% demand classification of fuel for the existing CTs and other capacity-related resources on the island system.

In assessing the appropriateness of COS methods, is important to focus on the fact that COS methodologies are driven by cost causation. Specifically, COS methods should reflect which uses of electricity by customers cause the incurrence of the cost. For the same reasons as set out above with respect to Holyrood plant-related costs, there is little basis to consider the Holyrood fuel as an energy benefit to the system, or to be caused by energy consumption. In this case, the fuel cost is caused by the need to keep the plant warm and in a ready state for full dispatch on short notice, which is a function of the need for the plant to be able to supply capacity at peak winter times. It is not a function of the energy consumed on the island. Consider the case of a customer altering their consumption of energy in summer or fall – they may alter the relative consumption of water in the island hydro plants, which may alter the quantity of exports or LIL inflows, but in no way will they alter the need to keep Holyrood warm to be able to be dispatched to meet peak winter conditions.

In effect, the fuel consumed at Holyrood in the 2027 Test Year is a fixed cost related to having the plant available for capacity reasons, not a variable energy cost. As a fixed cost, the fuel is appropriately classified in the same manner as the plant costs.

Comparing between the Hydro proposed 100% energy classification, a classification based on the Hydro proposed classification for Holyrood plant (11.19% energy) and 100% demand,[50] the impacts on class costs, after mitigation, are as shown in Table 4.2:[51]

Table 4.2: Impacts on Class Costs for Differing Holyrood Fuel Classification, After Mitigation

	Holyrood Fuel Classification Impact	
$000s	11.19% Energy	100% Demand
Newfoundland Power Wholesale Rate		
Change in Costs, after Mitigation	$0	$0
Impact on Total Allocated Costs	0.00%	0.00%
Island Industrial		
Change in Costs, after Mitigation	($2,368)	($2,666)
Impact on Total Allocated Costs	(5.50%)	(6.23%)
Labrador Interconnected		
Change in Costs, after Mitigation	($10)	($12)
Impact on Total Allocated Costs	(0.05%)	(0.05%)

Note that there is no adverse impact on any customer class from the re-classification of the Holyrood fuel from 100% energy to either 11.19% energy or 100% demand after mitigation.

As the COS allocations are properly rooted in cost causation, and there is limited to no cost causative link between annual energy consumption and Holyrood fuel consumption in the 2027 Test Year forecast, there is no basis to classify 100% of the Holyrood fuel to energy. Holyrood fuel should be classified consistent with the Holyrood plant, as it reflects the closest linkage to cost-causation for these costs.

Recommendation 5: Holyrood fuel should be classified consistent with Holyrood plant costs, reflecting the cost causation link with the reason these costs are incurred.

Consistent with the above approaches, any revised treatment for Holyrood fuel would also apply to the LTSCVDA, as proposed in the Application.

[50] Additional scenarios have been considered in the RFIs, including classifying 6.94% to energy (approximately mid-way between the above two changes) which is consistent with the relative ratio of fuel considered to be consumed to maintain unit availability, versus a small percentage considered to be consumed for dispatch above minimum. PUB-NLH-168 (d)

[51] Comparison of Schedule F 1.2 as filed, versus IIC-NLH-022 Attachment 1 (for 11.19% energy) and CA-NLH-154 Attachment 1 (for 100% demand)

4.4 NEWFOUNDLAND POWER GENERATION CREDIT AND CAPACITY ASSISTANCE PROGRAM

In the COS, demand-related costs are allocated on the basis of CP. This requires a measure of each class's expected contribution to CP.

In the case of NP, there are three adjustments considered to determine the COS CP value. Two relate to NP's generation (hydraulic and thermal) and one for NP's curtailable or capacity assistance loads.

In effect, NP's COS allocations for peak demand include recognition that the utility maintains a complement of generation assets that alter the peak loads Hydro must serve and plan for on the IIS. As capacity becomes of increasing importance on the IIS, these assets are valuable contributors to the IIS supply complement and credit is provided in the COS to recognize this value.

The 2019 COS settlement provides that:[52]

> The Parties agree that Hydro should continue to provide a generation credit for Newfoundland Power for hydraulic and thermal generation consistent with past practice. Hydro agrees to review the methodology for the calculation of the megawatt credit provided to ensure its reasonableness and to report on its review in its next General Rate Application.

Hydro prepared the requested analysis as part of the 2025 COS application. The result of the analysis is a 64 MW hydraulic generation credit provided to NP, and retention of the existing process for determination of a thermal generation credit.[53] Hydro also proposed to apply a 12 MW credit associated with the NP curtailable program.[54]

4.4.1 Hydraulic Generation Credit

The hydraulic generation credit reflects an ongoing, normal and expected use of the NP generation resources to supply loads on the IIS. As such, this is not a form of standby credit or call option, it is a means to appropriately model NP's expected Test Year loads on the IIS. This is an appropriate use of the approach of providing a credit against NP's native load in the COS, to reflect expected conditions.

The hydraulic generation credit has been updated based on a new methodology tied to historical generation during system peaks. Hydro has used the five-year historical average, from 2020-2024, to determine the 64 MW credit. This exceeds the average over a longer period (60 MW over the 2015-2024 period) or a

[52] 2019 COS settlement, item 33.
[53] Application, Volume 1, pdf page 26 of 464.
[54] Application, Volume I, section 6.6.7, pdf page 191 of 464.

credit based on historical generation measured based on lower probability thresholds (e.g., P90 at 53 MW).[55] Hydro also indicates it does not model a specific calculated load carrying capability of NP's hydraulic generation for planning purposes:[56]

> The hydraulic credit is based on demonstrated historical performance during Island Interconnected System peak loading periods. Historical operating and inflow conditions provide direct evidence of the amount of dependable capacity that has been available from the hydraulic system under a range of water conditions. By evaluating actual historical performance over multiple years, the hydraulic credit reflects the practical capability of the resource at peak, while inherently capturing the effects of varying hydrology, operational constraints, and system conditions.

Based on the above consideration, it is appropriate to adopt the 64 MW credit for NP's hydraulic generation.

Recommendation 6: Hydro's proposal to adopt a 64 MW hydraulic generation credit for NP for generation and transmission purposes is appropriate and should be adopted.

4.4.2 Thermal Generation Credit and Capacity Assistance/Curtailable

With respect to NP's thermal generation and curtailable load, Hydro proposes to permit NP a credit for the full thermal capacity of 44.5 MW, less a 13% reserve margin for a net 39.3 MW[57], plus 12 MW for curtailable load.[58]

The NP thermal generation is rarely dispatched for system purposes, occurring only 4 times in the last 5 years.[59] As such, the thermal credit value is not based on actual dispatch, but on availability. This also supports continuation of the longstanding practice that the thermal generation credit is not applied towards transmission costs, as the loads at peak times do not reflect NP dispatching its thermal generation.

The value of the credit received by NP for the thermal generation credit at this time is limited, due to the effect of mitigation funding, which limits rate impacts regardless as to underlying costs. The full unmitigated net impact of the credit on NP for thermal generation is $1.474 million, which is then allocated to other IIS customers.[60] However, this value masks the true economic benefit provided to NP for the thermal generation. This economic net effect on NP is the combination of 2 factors – a value provided to NP as

[55] PUB-NLH-108 (b).
[56] PUB-NLH-18 (c).
[57] Application, Volume 1, section 6.2, pdf page 183 of 464.
[58] Application, Volume I, section 6.6.7, pdf page 191 of 464.
[59] NP-NLH-104.
[60] Per IIC-NLH-011 Attachment 4, Schedule 1.2 ($1,011,097,757 allocated cost to NP before deficit without the thermal credit), as compared to Application, Schedule G 1.2 ($1,009,624,141 allocated cost to NP before deficit, with the thermal credit).

generator owner, for ownership of the thermal generation, less the share of that value that ought to be paid by NP's customers for service of that generator towards its own share of systemwide loads.

Quantitatively, NP is responsible for 88.74% of all costs incurred by Hydro for generation on the IIS.[61] As such, if Hydro incurs a generation related cost of $1 million, NP will be allocated $887,400 of that cost.

If Hydro was to credit a generator with $13.091 million as a net system cost, NP would be allocated $11.617 million of that cost. This is the essential economic transaction of the NP thermal generation credit as proposed by Hydro – an effective transfer of $13.091 million to NP for owning the generation, less $11.617 million of cost allocated to NP to pay for that cost, for a net beneficial impact on NP of $1.474 million (and a net cost impact on other customers of this same $1.474 million). This is because most of the benefit, at the IIS level, of the NP thermal generation relates to NP's own service, as the largest customer on the IIS.

Effectively the same mathematics apply to the 12 MW of curtailable load that NP maintains on its system, except that the curtailable load is presently provided both a generation and a transmission credit[62] so the effective value provided NP for this curtailable load would be even higher than assumed for the thermal generation credit per kW. Unfortunately, calculation errors in the RFI responses prevent determination of the precise value of the curtailable credit.[63]

There is no evidence that the NP's 44.5 MW of thermal generation provides $13.091 million in value to the system. This would be equivalent to $294/kW of generation made available. Compare this compensation to the value provided for other customer-related capacity resources provided to Hydro. For example, CBPP is provided only $83.80/kW-yr for capacity at varying levels throughout the year[64], and Vale's capacity assistance is credited at only $28/kW to provide 4 months of winter capacity.[65]

It is acknowledged that curtailable or capacity assistance supplies can be somewhat differently valued than generation, for various factors such as the following:

Factors leading to curtailable loads being less valuable than generation:

- Curtailable loads typically have limits on the number of times and maximum hours they can be called.

[61] Application, Schedule G 3.1A, page 1, column 3.
[62] Per IIC-NLH-011, Attachment 2, Schedule 3.1A, compared to Application Schedule G3.1A.
[63] The precise value should be derived from IIC-NLH-011 Attachment 2, except that that response appears to include a calculation error, in that Schedule 3.1A shows a net increase to NP 1 CP kW for Production Demand and Transmission Demand allocators, but an offsetting decrease to Rural loads, which is not correct – eliminating the 12 MW curtailable credit to NP would not decrease Rural loads. A corrected IIC-NLH-011 Attachment 2 (and 1) should be provided by NLH.
[64] PUB-NLH-110, Attachment 1
[65] PUB-NLH-110, Attachment 3, page 6 of 14, based on $7/kW-month times 4 months.

Factors leading to curtailable loads being more valuable than generation:

- Generation supplies require maintenance of reserves, so every MW of generation is less valuable than curtailable supplies, which release reserves when called.
- Generators do not always start, or respond to system emergencies in time. In contrast, curtailable loads can always be interrupted, and the utility can ensure the customer is not consuming power (whether by load diversity, or explicit interruption protocols).

As capacity becomes an increasingly important resource on the IIS, and more generation and curtailable loads are anticipated to be added, it is of increasing importance that fair and transparent treatment is afforded these supplies. A more appropriate, transparent and fair treatment of capacity supplies would be as follows:

- Hydro should make explicit annual payments for acquisition of capacity resources from all parties, including NP.
- Costs should be established based on the relation to marginal costs of capacity. For example, Manitoba Hydro considers curtailable load to be valued at 42% of the levelized cost a CT.[66] NP's thermal generation value to Hydro would also be benchmarked off the levelized marginal cost of a CT, but with a balanced sharing of the cost and value between NP and Hydro, given the role of NP's generation for both (a) local generation and backup during transmission outages (an NP customer-specific benefit), and (b) overall grid support during generation shortfall events (an NLH IIS-level benefit), which may be reasonably considered to be of equal value for simplicity.[67]
- Such costs should be paid as a component of revenue requirement, and the costs should be allocated in the COS based on 100% demand classification.
- Compensation for capacity resources (thermal generation and curtailable loads) should reflect relative value, and be non-discriminatory among all customers in terms of availability and cost.
- Payments to NP for their thermal generation and their curtailable loads should not be implemented by COS adjustments (as proposed by Hydro), which are neither transparent nor fairly applied with respect to other classes.
- Thermal and curtailable resource acquisition costs should be consistently linked only to generation, and not avoided transmission.

[66] Manitoba Hydro 2025 GRA, Appendix 7.15, Curtailable Rate Program Annual Report page 11.
[67] Note that NP described the function of the thermal assets as follows in their 2025-26 GRA: "Generation assets also include four combustion turbines and two diesel units which serve customers experiencing localized outages and provide system support when requested by Hydro". Page 2-14.

Adoption of the above provisions would ensure fair and transparent treatment of all capacity resources acquired from regulated customers of Hydro.

For the purposes of the current GRA, rejection of the thermal generation credit format will have no adverse impact on NP rates, given mitigation funding. A practical implementation of the thermal generation credit for this GRA can be achieved as follows:

- Benchmark the NP thermal generation value off of the existing CBPP capacity assistance agreement, at $83.80/kW.
- Using the Manitoba Hydro equivalence factor for curtailable loads versus full CT generation, this equates to $199.53/kW for CT equivalent.[68]
- Adopt an assumed 50% of NP thermal generation value for local load support (an NP customer specific benefit) and 50% for IIS support (a value to be recovered from Hydro). This yields $99.76/kW-yr as a reasonable Hydro-provided compensation for the NP thermal generation.
- Using the net contribution to Hydro IIS of 39.3 MW, this yields an annual value of payment to NP of $3.921 million.
- Consider the $3.921 million as a resource acquisition cost, equivalent to a PPA. Include this value in Hydro's revenue requirement, and classify the cost in the COS as an IIS 100% demand cost, equivalent to other demand-related acquisition costs.
- A similar mechanism should be applied to the NP curtailable loads (i.e., a payment to NP for its adoption of a curtailable program of 12 MW), benchmarked to the $28/kW provided to Vale, as an Hydro curtailable load, or a total of no more than $336,000. This payment to NP should also be included in Hydro's revenue requirement and recovered via the COS as a 100% capacity cost.

Note that with respect to fairness of treatment of NP, the 2022 Average Rate Base of NP's thermal assets was only $16.131 million[69] (it does not appear updated values since 2022 are available). As such a $3.921 million annual payment for the services of this plant is a 24% return on the NBV of the assets, solely for the portion considered of value to Hydro (not including the value generated by the thermal units in terms of local support unrelated to IIS generation shortfall requirements).

[68] $83.80 / 42%.
[69] Per NP 2025-26 GRA, Volume 2, pdf page 77 of 259. Total O&M on this thermal generation function was listed at $581,000 in 2022, per NP 2025-26 GRA, Volume 2, pdf page 82 of 259.

Recommendation 7: The proposed 39.3 MW thermal generation credit to NP in the COS should be rejected, as well as the 12 MW curtailable load credit.

Recommendation 8: A revised approach to capacity resource acquisition should be implemented, based on fair and transparent treatment of all dispatchable and periodic customer resources (thermal generation and curtailable).

Recommendation 9: For the purposes of the 2027 Test Year, a thermal generation credit for NP should be premised on a $3.921 million payment to NP for the services of its thermal generation, and a payment of no more than $336,000 to NP for the services of its curtailable program based on 12 MW of capacity. These costs should be part of Hydro's revenue requirement and included in Hydro's COS allocations based on a 100% demand classification.

Recommendation 10: Dispatchable capacity related credits in the COS study (thermal generation or curtailable) should not be considered an adjustment to transmission cost allocation.

Future IIC curtailable programming, capacity assistance, and related non-firm opportunities are addressed in Section 5 of this submission.

4.5 WIND GENERATION CLASSIFICATION

Prior to 2013, Hydro had classified wind purchases to be consistent with hydraulic resources, rather than based on the specific performance characteristics of wind. Hydro noted at the time its wind purchases since 2009 had a capacity factor in excess of 40% and that Hydro used a 40% capacity factor for wind in its planning, but not in COS.[70] In the amended 2013 GRA, Hydro proposed that wind generation be classified 100% to energy on the basis that wind generation was justified on the basis of reduced fuel cost at Holyrood and that Hydro no longer assumed wind generation would be available to supply system capacity requirements.[71] The 100% energy classification was agreed to as part of the supplemental settlement agreement dated September 28, 2015 with the understanding it, along with all COS method issues generally, would be included as part of a future COS methods review.[72]

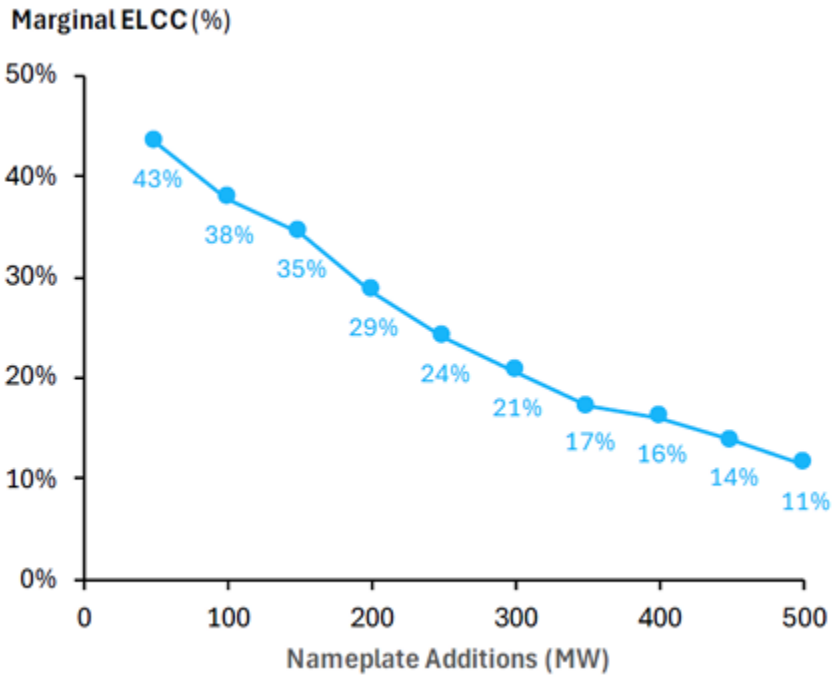
In the 2018-19 COS methodology review proceeding, Hydro noted the interconnection to the continental grid changed its operational perspective and it revisited its assessment of the capacity value of wind generation. Hydro completed an Effective Load Carrying Capability (**"ELCC"**) Study that found its wind

[70] Response to RFI NP-NLH-162 from the NLH 2013 GRA.
[71] Section 4.3.2. Amended 2013 General Rate Application. Page 4.15.
[72] Paragraphs 7 and 13 of the supplemental settlement agreement dated September 28, 2015.

resources at the time yielded ELCC ratings of approximately 22%.[73] The 2019 settlement agreement included a provision that power purchase costs for wind generation on the Island Interconnected System would be classified consistent with its ELCC rating; that is, 22% demand and 78% energy.[74]

For the 2026 GRA, Hydro engaged an external consultant to study the ELCC values for wind, solar and battery storage. The study found wind generation can more often overlap with morning and/or evening peak demands, and that the marginal firm capacity ratio associated with 50 MW of wind generation was approximately 43%. The marginal capacity ratio decreases with higher incremental wind additions as shown in Figure 4.1: [75]

Figure 4.1: Wind Marginal ELCC



Hydro acknowledged the study was intended for the purpose of long-term resource planning but took the position that it was appropriate for the use of cost classification for its existing facilities. Hydro noted the ELCC study was completed using data from the existing wind generation sites and that the size of the existing 54 MW wind fleet is similar to the 50 MW increment presented in the study.[76] On that basis, Hydro

[73] Lines 7 through 10. PDF page 84 of 144 of the November 15, 2018 COS Methodology Review application.
[74] Paragraph 25 of the 2019 settlement agreement. Included as Schedule A to Board Order P.U.37(2019).
[75] PDF page 736 of 816. Volume III NLH 2026 General Rate Application.
[76] Response to PUB-NLH-103.

is proposing to classify wind generation on the Island Interconnected System as 43% demand and 57% energy.[77]

The change from the previous 22% demand/78% energy classification ratio to the proposed 43% demand/57% energy classification ratio results in the following changes to costs after mitigation: [78]

- No net impact on NP wholesale rates
- Island industrial customers – a reduction of $130,000, or 0.30% of total allocated costs.
- Labrador interconnected – a reduction of $1,000, or 0.01% of total allocated costs
- An increase in mitigation funding of $131,000

The use of a classification ratio for wind generation based on ELCC studies, or other approaches that yield classification ratios in the range proposed by Hydro, is shared in neighbouring jurisdictions. For example, Maritime Electric classified wind based on ELCC.[79] Similarly, Nova Scotia Power previously classified its wind assets based on their ELCC which had been its long-standing practice (however in that GRA it updated the practice to use the system load factor, which leads to a 54% classification to energy, very similar to the Hydro proposal).[80]

Use of the updated ELCC study appropriately reflects the role of existing wind generation on the Island Interconnected system. It is also consistent with the methods adopted when the parties negotiated the 2019 negotiated settlement.

Recommendation 11: Hydro's proposal to use the updated ELCC values to classify wind generation between demand and energy should be approved.

[77] Lines 3 through 5. Page 6.10. Volume I NLH 2026 General Rate Application.
[78] IIC-NLH-033 Attachment 1.
[79] Maritime Electric 2020 Cost Allocation study, page 13, at a 23% classification factor. https://irac.pe.ca/wp-content/uploads/Exhibit-M-1d-REVISED-2020-Cost-Allocation-Study-dated-January-27-2022.pdf pdf page 15 of 111.
[80] PDF pages 13 and 1035 of 1738. NSP GRA Appendix 12. Exhibit N-9 in Nova Scotia Energy Board Matter M12451.

5.0 INDUSTRIAL RATE DESIGN

5.1 OVERVIEW OF CURRENT ISLAND INDUSTRIAL CUSTOMER RATES

The rate structure for industrial customers served on the island is established by way of the Rate Schedules as approved by the Board from time to time, and the individual industrial contracts, which are approved by the Board at the time of changes. The current industrial contracts are filed in response to PUB-NLH-047.

The current rates to Island Industrial Customers reflect a combination of Firm Power and Energy, and Interruptible Demand and Energy, as these terms are defined in the contracts.[81] In the Rate Schedules, Interruptible Demand and Energy is priced under the "Industrial Non-Firm" Rate Schedule.

The basic structure of the industrial rate in terms of being a flat combined demand and energy pricing has not materially changed in decades, with the exception of an update to the non-firm energy pricing, which retains the same principle historically used (i.e., marginal cost-based pricing) but is now priced based on a coarse linkage to market opportunity costs.[82]

The pricing of industrial **Firm Power and Energy** supply is as follows:

- A charge for demand of $10.73/kW per month based on each customer's contracted Power on Order (**"PO"**)[83]
- A charge for energy comprised of:
  - a base energy charge of 4.428 cents/kWh approved as part of the 2019 GRA
  - a supplemental energy charge, entitled the Project Cost Recovery (**"PCR"**) rider of 2.015 cents/kWh implemented to recover a portion of the costs of the Muskrat Falls project which was implemented after the 2019 GRA[84]
- A rider to recover Conservation and Demand Management (**"CDM"**) costs of 0.007 cents/kWh, last updated in 2026

[81] Where relevant, the contracts also provide for Generation Outage Demand and Energy, e.g., in PUB-NLH-047, Attachment 3. Further, Secondary Energy is provided for in the contracts but is understood to not be anticipated to be available in the Test Year.

[82] P.U. 34 (2023); "The Board approves Hydro's application to implement a non-firm rate for the Labrador Interconnected System to be calculated based on export market prices on the basis that non-firm energy sales will reduce the energy available for export. The Board also approves a proposed revision to the Island Industrial customer non-firm rate to be consistent with the Labrador Interconnected System non-firm rate and to better reflect marginal costs." Page 1.

[83] In rare instances the contracts provide for demand billing above PO in the event (1) the customer exceeds their full PO plus Interruptible Demand, or if they exceed their PO and Interruptible Demand is not available, or (2) the customer has materially dropped their contracted PO in the last year. It is not apparent that this has led to any (or any notable) charges since 2019, per CA-NLH-006 Table 1.

[84] Page 6.22. Volume I of NLH 2026 GRA.

- A customer-specific Specifically Assigned Charge (**"SAC"**) based on the assets required only to serve a given customer. SAC levels were last updated in the 2019 GRA.

In terms of **Interruptible Demand and Energy** (also known as Non-Firm Energy), Island Industrial Customers have access to a specified quantity of this non-firm product which appears to vary based on the vintage of the customer. Industrial contracts before 2020 have a scaled availability of non-firm power linked to 10% of the customer's PO, and no less than 5 MW, so long as PO is over 20 MW. If PO is below 20 MW, then non-firm power is limited to 25% of PO. Since 2020, the new industrial contracts appear to provide for a maximum 5 MW of Interruptible Demand, not linked to PO.[85]

The basis for discriminatory access to non-firm service is not made clear.

Hydro indicates that the capped nature of access to non-firm power is constrained to reflect Hydro's preference:[86]

> The 5 MW interruptible power limit reflects Newfoundland and Labrador Hydro's ("Hydro") longstanding assessment of the amount of non-firm load that can be reasonably accommodated while preserving the fundamental characteristics of interruptible service and maintaining the priority of firm service.
>
> …
>
> Hydro has historically administered interruptible service as a limited product that utilizes available capacity without displacing firm load or requiring Hydro to plan its system to serve the interruptible demand on a firm basis.
>
> …
>
> Accordingly, Hydro considers it appropriate that access to interruptible power be provided within defined limits that reflect practical operating considerations rather than as an unrestricted entitlement.

Interruptible or non-firm service is only made available at Hydro's discretion.[87] When using non-firm service, industrial customers rates are based on one of two factors tied to the marginal supply cost:

- Typically, prices reflect the export market, and the revenue Hydro would have received from exporting this power.

[85] PUB-NLH-047. The new terms apply to CBPP (2021) and Marathon Gold (2022).
[86] IIC-NLH-024 (b).
[87] Response to IIC-NLH-024 (a).

- Consistent with the principle of marginal cost pricing, when the alternative supply source of power is not foregone exports but instead derives from added use of island-based thermal resources (e.g., Holyrood, or CTs), the price for non-firm power reflects the incremental cost of this alternative source.[88]

The most recent update to non-firm rates provides that the pricing is distinct between off-peak and on-peak periods, and varies by month. Customers are advised in advance of the pricing for the upcoming month (on the first business day following the 21st of the preceding month)[89]; however, the rate schedules and industrial contracts do not specify a fixed advanced customer notice to be provided when the rates are revised upwards due to the dispatch of thermal generation.

Hydro forecasts no non-firm consumption in the 2027 Test Year, consistent with the principle that these sales are net neutral financially to the utility.[90]

The Industrial Firm Power and Energy rates are a classic form of industrial rate structure widely used in Canada, comprised of a demand charge and a single block energy charge. The use of contract demand (PO) for the majority of demand pricing is not typical, but has been longstanding practice in this province.

In order to consider potential improved price signals on Firm Power and Energy, alternative potential rate structures for the island industrial rate schedules have been reviewed in the past, including:

- **2008-2013:** A 2008 review that included options for a two-block energy rate with the tail block or second block priced at Hydro's marginal cost of supply. This review, which was a collaborative process between a number of the island industrial customers and Hydro, was initiated pursuant to an agreement on COS, rate design and the rate stabilization plan filed as part of Hydro's 2006 GRA.[91] Although the investigations resulted in a potential alternative design, no common agreement was reached at that time, and the settlement agreement related to the amended 2013 GRA agreed to continue the current rate design for the IIC.[92] In the 2013 GRA, Hydro proposed to review the IIC rate design following the completion of a new marginal cost study and new rate design review.[93]
- **2019:** A 2019 internal review by Hydro proposed to maintain the existing approach to calculating a demand charge and implement a two-block energy rate with the first block set based on a customer's PO for a certain number of hours each month. The second block was

[88] Page 6.24. Volume I of NLH 2026 GRA. The pricing includes a floor price using the energy rate applicable to Rate Schedule 2.4L.
[89] https://nlhydro.com/wp-content/uploads/2025/07/Schedule-of-Rates-Rules-and-Regulations_Jul_2025.pdf
[90] PUB-NLH-060 (c).
[91] Review of Industrial Customer Rate Design. February 5, 2008.
[92] PDF page 110 of 145 of P.U.49(2016).
[93] Pages 4.30 and 4.31 of Volume I of Hydro's Amended 2013 GRA. Dated November 10, 2014.

referenced to the annual average unit value of exports. The first block would then be calculated to be the rate necessary to yield the approved class revenue requirement.[94]

No changes to the industrial rate design have been implemented to date based on these initiatives.

5.2 PROPOSED INDUSTRIAL RATE RECOVERIES

In the current GRA, Industrial rates for the test year are proposed to be established based on the output of the rate mitigated COS study (Schedule F of the application). The total proposed recoveries from firm rates is $42.815 million (exclusive of CDM rider, and any future PCR to continue the Muskrat Falls phase-in). This is a reduction of $8.778 million from the revenue at existing rates of $51.593 million (including the now existing PCR, which will become part of firm base rates).

This reduction in allocated IIC revenue requirement is consistent with the implementation of the new COS methods described in Section 4 of this evidence, which are being implemented for the first time since the 2019 and 2025 COS settlement agreements. The change is also consistent with the broad effects on the island interconnected system from the material reduction of Holyrood fuel costs, and other cost items that were part of base rates in the previous GRA, but which are no longer required since the implementation of Muskrat Falls supplies to the island.

In response to IIC-NLH-008, Hydro has provided illustrative rates that would apply if the existing form of industrial rate was retained and applied to the new GRA revenue requirements. The IIC base rates would be a $12.00/kW demand charge, and a 4.77 cents/kW.h energy charge for all energy consumed each month.[95] This rate combination would replace the current Demand charge, Energy charge and PCR.

In addition, in mid-2027 Hydro is anticipated to start to add a new PCR of 0.23 cents/kW.h, to begin the next step in the phase-in of Muskrat Falls costs. This rider is not yet being requested as part of this proceeding.

The net effect of the status quo illustrative rates is a 12% increased price signal regarding demand use (from $10.73/kW to $12.00/kW) and a 26% decreased price signal on energy use (from the combined energy charge of 6.443 cents/kW.h inclusive of the current PCR, to 4.770 cents/kW.h).

This pricing update is consistent with the broad cost drivers on the system – with increased demand driving investment, and reduced energy cost drivers (exports versus Holyrood) as compared to the last GRA.

[94] Summarized from section 5.0. Wholesale and Island Industrial Rate Design Review Update Report. September 30, 2019.
[95] IIC-NLH-009.

5.3 PROPOSED NEW INDUSTRIAL RATE STRUCTURE

While Hydro has calculated the rates using the existing structure in response to IIC-NLH-008, Hydro is proposing a new rate structure for the IICs based on an hours-of-use model. The proposed new rate is similar to the outcome of the 2019 review, but adds a seasonal component to the second block energy rate. The proposed rate would replace the current demand and energy charges (but not the CDM rider or SAC), as follows:

1. A demand charge of $5.50/kW which is a material reduction from both the existing demand charge of $10.73/kW, and the $12.00/kW demand charge under the existing rate structure. The demand charge would still apply to each customer's contracted PO.
2. A first block of energy each month, which is applied to energy consumption based on usage up to a load factor of approximately 41.1%. This is equivalent to approximately 300 hours of use for each kW of PO. The proposed first block rate is 6.694 cents/kW.h, which would effectively replace the existing energy charge plus the existing PCR (a combined 6.443 cents/kWh), and would be a significant increase over the illustrative GRA status quo rates of 4.770 cents/kW.h.
3. A second block of energy each month, comprised of all firm energy consumed in excess of the first block. This second block would have seasonally distinguished prices intended to approximate the value of exports in each season (i.e. winter and non-winter).
    - In the non-winter months (8 months from April through November) the second block energy would be priced at 3.285 cents/kWh (roughly 50% lower than the current energy rate inclusive of PCR, of 6.443 cents/kW.h, and 31% lower than the illustrative GRA status quo rates of 4.770 cents/kW.h).
    - In winter months (December through March), the energy would be priced at 8.889 cents/kWh, roughly 38% higher than the current energy rate inclusive of PCR, and 86% higher than the illustrative GRA status quo rates.

Table 5.1 compares the existing IIC rates, illustrative rates for 2027 using the current rate design and the anticipated July 1, 2027 new PCR, and Hydro's proposed rates for 2027 with the two-block energy rate: [96]

[96] Application, Volume 1, Table 6-9; pdf page 198 of 464. Illustrative rates from IIC-NLH-009.

Table 5.1: Comparison of IIC Rates and Revenues – Existing, Illustrative Using Existing Rate Design, and GRA Proposed

		Current Rates		Illustrative at GRA Rev Req		GRA Proposed	
	Billing Units	Rate	Revenue	Rate	Revenue	Rate	Revenue
Demand ($/kW/month)	1,095,600	10.73	$ 11,755,788	12.00	$ 13,147,200	5.50	$ 6,025,800
Energy ($/kWh)	613,371,000	0.04428	$ 27,160,068	0.04770	$ 29,254,995		
First block ($/kWh)	326,360,000					0.06694	$ 21,846,538
Second block winter ($/kWh)	91,034,000					0.08889	$ 8,092,012
Second block non-winter ($/kWh)	195,977,000					0.03285	$ 6,437,844
Project Cost Recovery Rider ($/kWh)	613,371,000	0.02015	$ 12,359,426	0.0023	$ 1,410,753	0.0023	$ 1,410,753
CDM Recovery Rider ($/kWh)	613,371,000	0.00007	$ 42,936	0.00007	$ 42,936	0.00007	$ 42,936
Specifically Assigned Charges			$ 318,130		$ 413,404		$ 413,404
Total			**$ 51,636,348**		**$ 44,269,288**		**$ 44,269,288**
			Total Change ($)		(7,367,059)		(7,367,059)
			Total Change %		-14.3%		-14.3%

Table 5.1 indicates the GRA target revenues (inclusive of the anticipated July 2027 PCR) result in a reduction to total revenues from the IIC of approximately $7.4 million (14.3%). This applies whether using the illustrative GRA status quo rates, or the proposed new industrial rates.

Based on the billing determinant forecast by energy block provided by Hydro and summarized in Table 5.1, Hydro anticipates approximately 53% of energy would be purchased at the first block rate; 32% would be purchased at the non-winter second block rate and 15% would be purchased at the winter second block rate.

Table 5.2 breaks down the changes in revenue impacts for the proposed rates compared to the existing rates (including the current PCR, but excluding the SAC).

Table 5.2: Comparison of Revenue Changes by Billing Component inclusive of Existing Project Cost Recovery Rider

		Current Rates		GRA Proposed		Change	
	Billing Units	Rate	Revenue	Rate	Revenue	$	%
Demand ($/kW/month)	1,095,600	10.73	$ 11,755,788	5.50	$ 6,025,800	$ (5,729,988)	-48.7%
First block ($/kWh)	326,360,000	0.06443	$ 21,027,375	0.06924	$ 22,597,166	$ 1,569,792	7.5%
Second block winter ($/kWh)	91,034,000	0.06443	$ 5,865,321	0.09119	$ 8,301,390	$ 2,436,070	41.5%
Second block non-winter ($/kWh)	195,977,000	0.06443	$ 12,626,798	0.03515	$ 6,888,592	$ (5,738,207)	-45.4%
Total			**$ 51,275,282**		**$ 43,812,948**	$ (7,462,333)	-14.6%

Table 5.2 shows the majority of the decrease relates to the lower demand charge ($5.729 million of the $7.462 million decrease) with the net change across all the energy blocks contributing a smaller portion of the total decrease. As a result, the revenue impact in a typical month is different between winter and non-winter months, as shown in Table 5.3.

Table 5.3: Comparison of Seasonal Revenue Changes by Billing Component inclusive of Existing Project Cost Recovery Rider

		Current Rates		GRA Proposed		Change	
	Billing Units	Rate	Revenue	Rate	Revenue	$	%
Typical non-winter month (Apr to Nov)							
Demand ($/kW/month)	91,300	10.73	$ 979,649	5.50	$ 502,150	$ (477,499)	-48.7%
First block ($/kWh)	27,196,667	0.06443	$ 1,752,281	0.06924	$ 1,883,097	$ 130,816	7.5%
Second block non-winter ($/kWh)	24,497,125	0.06443	$ 1,578,350	0.03515	$ 861,074	$ (717,276)	-45.4%
Total			**$ 4,310,280**		**$ 3,246,321**	$ (1,063,959)	-24.7%

		Current Rates		GRA Proposed		Change	
Typical winter month (Dec to Mar)		Rate	Revenue	Rate	Revenue	$	%
Demand ($/kW/month)	91,300	10.73	$ 979,649	5.50	$ 502,150	$ (477,499)	-48.7%
First block ($/kWh)	27,196,667	0.06443	$ 1,752,281	0.06924	$ 1,883,097	$ 130,816	7.5%
Second block winter ($/kWh)	22,758,500	0.06443	$ 1,466,330	0.09119	$ 2,075,348	$ 609,017	41.5%
Total			**$ 4,198,260**		**$ 4,460,595**	$ 262,334	6.2%

5.3.1 Rationale For The Proposal

In support of the proposal, Hydro states the proposed rate design changes are necessary because with the commissioning of the Muskrat Falls Project, Hydro's marginal cost of energy moved from No. 6 fuel consumed at Holyrood to the opportunity cost of the market value of exports.[97]

Hydro also suggests there would be benefits from bringing structural consistency between the IIC rate and the wholesale power rate structure billed to NP.[98] However, this appears to be, at best, a secondary rationale, as the commentary almost exclusively focuses on energy price signals.

In support of the proposal, Hydro provides detailed backup for the development of the winter and non-winter second block rates.[99] The design of these price signals on energy appears to be the driving factor behind the calculation of the remainder of the rate. The second block energy rates are designed to target 100% recovery of the average seasonal hourly market price, based on the Salisbury netback price, adjusted for relevant loss factors and currency exchange.[100] The values are the full marginal cost values, not adjusted for any form of rate mitigation.

The three other key variables are the demand rate, the first block energy rate, and the selection of the hours-of-use. In each case, it appears Hydro has used broad judgment to develop the factors, as follows:

[97] Page 6.17 line 14 through page 6.18 line 3. Volume I of NLH 2026 GRA.
[98] For example, see GRA application, section 6.7.1.
[99] For example, PUB-NLH-131 Attachment 1.
[100] PUB-NLH-131.

- The Demand Rate of $5.50/kW was lifted from the NP wholesale rate design.[101] The rate bears no relation to the current rate ($10.73/kW), nor the average embedded unit costs of demand for industrial customers ($17.54/kW-month under the mitigated COS, or $28.88/kW/month for unmitigated).[102] The rate is also entirely delinked from the marginal cost of capacity of $351/kW-yr for winter seasonal capacity (over $80/kW-month if calculated over 4 months).[103]

- The first block sizing of approximately 300 hours per month (41.1% load factor) arises from an analysis targeting the highest reasonable cutoff which placed most customers into a zone where some amount of second block use is anticipated for most months. Given the diverse range of customer profiles, and monthly load variation, the 300 hours cutoff value broadly satisfied the test.[104]

- The first block pricing (6.924 cents/kW.h) is simply a derived value to yield the targeted 100% revenue to cost ratio. It is not specifically linked to any individual cost item. It does not reflect the embedded unit costs for the mitigated values (3.780 cents/kW.h), though it happens to be reasonably close to the unmitigated value (7.341 cents/kW.h).[105] The rate is not linked to either the winter or non-winter marginal cost values, as used in the second block pricing. However, as an inframarginal rate, it is unlikely to be the prevailing cost signal for any customer in any month except for limited cases. Therefore, the need for this first block price to link to a specific cost value is less acute.

The timing for the Hydro proposal to take effect in 2027 is noteworthy, in that the marginal energy values being targeted (3.285 cents/kW.h in summer, and 8.889 cents/kW.h in winter) are far below the marginal costs of energy Hydro experienced in past years before the Muskrat Falls project. For example, in the 2019 GRA, marginal costs on the island were 18.2 cents/kW.h[106], and the costs were 15.37 cents/kW.h in the 2013 GRA[107]. It has likely been 20 years, since the 2006 GRA, when Hydro's marginal costs for energy were last in the range of 9 cents/kW.h, and at that time this marginal cost applied throughout the year, not just in winter.[108]

[101] GRA Application, section 6.7.1.
[102] Appendices F and G, Schedules F1.3 and G1.3 respectively.
[103] IIC-NLH-037 (b). The rate is also below the marginal capacity cost of the new Avalon CT, of $388.92/kW-yr, per CA-NLH-321 (c).
[104] GRA Application, Volume III, Exhibit 17, page 14 (pdf page 803 of 816).
[105] Appendices F and G, Schedules F1.3 and G1.3 respectively.
[106] $105.90/bbl and an efficiency of 583 kW.h/bbl, per 2013 Application, Schedule A-V.
[107] Hydro's 2015 GRA Volume I section 4.5.1, footnote 33.
[108] $55.88/bbl and an efficiency of 617 bbl/kW.h, per 2006 Application, Schedule IV.

In short, the marginal price signals Hydro faces, and for which the second block rate design is premised, are if anything far less acute (even in winter) than in past proceedings. As such, the basis for Hydro's rationale for implementing the two-block rate at this time is weak, and merits careful review.

5.3.2 Issues with Proposed Industrial Rate

Based on the review to date, the proposed new industrial rate form does not appear to be a well-designed nor appropriate evolution of the Hydro industrial rate offering. This is for three reasons:

1) **Excessive focus on energy:** For the current island system, the main drivers of investment and increasing economic pressure are capacity or demand, not energy. Hydro is initiating material and complicated new investment to make sure it can meet peak demands (e.g., CTs, and BDE 8), and anticipates further upward pressure on demand if electrification and load growth activities accelerate.[109] At the same time, consistent with its peer utilities, Hydro has considerable available new energy resources that can be constructed relatively easily (for example, wind)[110]. While winter energy is a cost pressure on Hydro from short-term forgone exports, it is less of an economic driver than energy in past GRAs, when Holyrood oil was the marginal supply.

   The proposed rate reflects capacity pricing that significantly under-collects both embedded and marginal costs of capacity, yet proposes to reduce the capacity charge by almost 50% in favour of increased marginal price signals on energy. Given the current and evolving system supply conditions, the efforts appear to be misaligned, if not entirely contrary, to efficient price signals.

2) **Failure to Achieve Primary Objective of New Rate:** While Hydro states the rate design is intended to improve efficiency in pricing and incentivize customers to increase their load factor[111], the proposed rate design actually acts in a contrary fashion for the most critical periods. Given that a customer must set a single PO for the year (which means the demand charge acts more like a fixed charge) the only price signals inherent in the new rate are for energy. After reaching a 41.1% load factor, with the first block energy unit price set at 6.924 cents/kW.h, the summer second block price of 3.515 cents/kW.h would incentivize increasing the load factor. However, in winter, the second block price of 9.119 cents/kW.h would incentivize avoiding further energy use at the given

[109] RRA Technical Conference 3, Issues 5 and 6 Presentation. http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%203%20-%20Scenarios%20and%20Sensitivities%20-%20Modelling%20Approach%20and%20Considerations%20-%202024-10-16.PDF pdf page 103 of 106.

[110] Hydro references a call for expressions of interest for wind, and in the 2024 RRA Technical Conference 3 regarding Issues 5 and 6, Hydro indicated that all modelling results indicated wind was the least-cost energy solution for all scenarios modelled.

[111] Application, Volume 1, Section 6.7, page 6.19; pdf page 193 of 464.

PO, which is a signal to lower the customer's load factor (or to opt for added PO to increase the availability of first block priced energy, which is also a load factor reducing maneuver).

Reducing the price signal on demand is also a factor pressuring reductions in load factor. This is evidenced by the fact that the proposed new rate reduces bills for lower load factor customers and raises them for higher load factor customers.[112] Hydro states this fact is not a weakness of the proposed rate design but simply reflects the redistribution of costs typical of transition to a new rate structure and may also support customer acceptance of the rate transition.[113] However, beneficial outcomes for customers with the lowest load factors (which are the purportedly adverse load characteristics Hydro is seeking to avoid) does not indicate alignment between the stated goal and the proposed rate solution.

This outcome also does not appear to be specific to the unique seasonality of customer loads used in the Christensen Report. The scenarios provided in response to IIC-NLH-008 model different load factors distributed equally throughout the year, and these scenarios also indicate the lowest load factor customer would see a bill reduction while the highest load factor customer sees the largest bill increase compared to the existing rate design.

3) **Excessively narrow consideration of industrial rate package:** Hydro has developed the new rate proposal through a narrow consideration of only revisions to industrial firm rates, and not to opportunities provided by potential changes to non-firm offerings, demand pricing structure, or load changes (such as industrial customer electrification options). Such changes would properly be part of a fulsome rate redesign effort intended to meet customer needs and improve effective price signals. For example, retaining a firm demand charge entirely linked to a single annual PO level reduces incentives to manage peak demands to levels below contracted PO, and reduces flexibility to tailor PO by month. Similarly, the non-firm rate offered by Hydro is limited in quantity (5 MW) and pricing granularity (monthly on-peak and off-peak), such that it is not a material component of industrial consumption on the island.

Hydro noted it would file a report on its experience with the monthly peak and off-peak non-firm rates, but not until June 1, 2028[114], and the results could inform whether there are potential benefits to more frequent pricing updates.[115] For customers that may have options for electrification or other load management options, such granularity of off-peak pricing (combined with increased

[112] Application, Volume 3, Exhibit 17, Tables 1 through 4. Pdf pages 799-800 of 816.
[113] IIC-NLH-002.
[114] In place since March 1, 2024. P.U. 23 (2026)
[115] IIC-NLH-005.

access to off-peak power above 5 MW) may well be beneficial and improve price signals more than the current proposal to solely adjust firm rates.

As a comparison, the suite of power supply options available to industrial customers in other jurisdictions comprises far more than simple standard-form firm demand and energy supply using one- or two-block rates. For example, in New Brunswick, Large Industrial customers are also offered Surplus or Interruptible Energy at market-based marginal costs without limits such as the 5 MW cap imposed by Hydro[116]; in Nova Scotia, industrial customers can access energy under firm pricing or Real Time Pricing, as well as participate in interruptible capacity programs to an unlimited degree (Hydro only permits this under the "Capacity Assistance Agreements" individually negotiated, and not considered a regulated rate)[117]; British Columbia Hydro offers supportive electrification rates[118] as well as a new suite of time-of-use and critical peak pricing options.[119] In each case these rates are understood to reflect the particular cost characteristics of the system in question, and would likely not transfer directly to Hydro's fact profile. However, similar cooperative rate evolution may well be possible in this province.

It should also be noted that modern industrial rate design efforts can also be coordinated with opportunities for industrial customers to pursue new self-generation, such as a concurrent new industrial rate offering being reviewed in Nova Scotia, among others.[120]

In addition to these fundamental issues with the new rate proposal, the following concerns are also noted:

Limited Customer Engagement

Hydro stated it engaged with legal counsel representing the IIC Group regarding proposed changes to the IIC rate structure and shared information with customers through their Key Accounts representatives.[121] However, this engagement was limited to a virtual meeting and presentation with legal counsel on April 16, 2026, followed by sharing of the unredacted versions of the rate design option impacts specific to their clients on May 13 and May 14, 2026. The April 16, 2026 presentation was shared directly with customers

[116] https://www.nbpower.com/media/1494118/2026-27-rate-schedules-and-policies-effective-2026-04-14.pdf, pdf pages 54-59. Note that the program was suspended to new customers in 2021 due to crypto-mining requests for supply, although NB Power retains the ability to supply new loads at its discretion.
[117] https://www.nspower.ca/your-business/save-money-energy/business-rates
[118] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/non-residential-rates/electrification-rates.html . Applies to RS 1894 and RS1895
[119] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/non-residential-rates/transmission-rates.html for RS 1892, RS 2801, RS 2802, RS2821, and RS 2822 as well as a Time Varying Rate Pilot.
[120] Nova Scotia Energy Board proceeding M12661; also see M11301 in regard to direction to develop a new rate structure that can accommodate the new wind generation.
[121] PUB-NLH-048.

on May 29, 2026.[122] As the GRA was filed on May 27, 2026, IICs had no practical ability to respond to the proposal prior to the GRA being filed.

Limited Options Considered

With respect to alternative possible rate designs to address the noted design objectives, Hydro indicated that it only considered variations on the hours of use model described in the Christensen Associates report attached as Exhibit 17 to the GRA.[123] Hydro further confirmed it did not consider time-varying pricing designs that include daily or weekly peak and off-peak prices for firm energy, or revisions to non-firm energy access.[124]

The lack of alternatives considered limits the ability to evaluate whether other options would provide better cost tracking or incentives for customers to shift loads away from peak periods.

Poor Justification for Including March as a Winter Month

Hydro's proposal includes March as a winter month, despite the fact forecast export prices for March are much lower than December, January or February and slightly lower than July and November as shown in Table 5.4: [125]

[122] IIC-NLH-026.
[123] IIC-NLH-001.
[124] IIC-NLH-005.
[125] IIC-NLH-003 (b).

Table 5.4: Seasonal Export Prices weighted by Island Industrial Customer Usage

Month	Weighted Price (¢ per kWh)	IIC Usage (GWh)
January	12.77	50.23
February	10.06	42.00
March	4.34	51.61
April	2.56	45.60
May	2.31	56.94
June	2.72	53.11
July	4.75	57.75
August	4.25	57.13
September	2.70	55.39
October	2.67	51.30
November	4.47	36.15
December	8.72	56.16
Winter Weighted Average (December-March)	**8.889**	
Non-Winter Weighted Average (April-November)	**3.285**	

Hydro states switching March to a summer month would raise both the first and second block price. While this is accurate, it ignores the benefits that arise from the higher winter second block rate only applying to three months of the year rather than four as proposed, with the much lower summer second block rate applying in March. Hydro states it includes March as a winter month because that is within the four-month period when peak loads on its system are likely to occur. Hydro provided information showing only 5 instances since 1985/86 when the peak load occurred in March[126] (with only one instance in the last 30 years), and further acknowledged that the interconnection with the eastern North American grid has exposed Hydro to loads, capacities and reserve conditions of the Eastern Interconnection that do not reflect winter-type pricing for March exports.[127]

If the intent of the rate design is to mirror marginal costs based on export market opportunities, it is not clear why Hydro would define the winter period for rate design purposes based on relatively infrequent peaks on its own system, instead of the broader trends in its export markets. Doing so risks creating an improper price signal that deviates from the market references Hydro states are the basis for its proposed rate design.

[126] IIC-NLH-028.
[127] IIC-NLH-003.

5.3.3 Recommended Changes

Hydro's proposed revisions to the IIC rate design are poorly supported and do not satisfactorily address a range of issues, including appropriate incentives to minimize peak demands, maximize load factor and make use of interruptible energy for electrification of certain loads. The rate proposal fails to achieve the objectives it seeks to fulfill (provide price signals for increases in load factor) and will likely undermine more important demand-related cost pressures on the system.

Hydro stated it would be amenable to establishing a working group with representatives from the IICs to explore improvements and alternatives to the proposed industrial rate design, but indicated such process would occur following the implementation of the proposed rate design.[128] Attempting to modify an inferior rate design after it has been implemented would not be a reasonable outcome for customers.

The Board should not approve Hydro's rate design as proposed, and should instead direct Hydro to participate in a process with the IICs to develop a new proposal that more fulsomely addresses the above noted suite of issues, as well as opportunities related to new access to export markets (particularly lower priced off-peak and summer exports). Objectives of the new rate should be clearly established beyond simply energy price signals, and include improved access to non-firm energy and support of electrification possibilities.

> **Recommendation 12: Hydro's proposed changes to the IIC rate design should not be approved. Instead, the Board should direct Hydro to participate in a process with the IICs to develop a new proposal focused on potentially improving both energy and demand price signals across both firm and non-firm energy, as well as support for electrification or self-generation.**

At minimum, if the Board decides it will approve the proposed rate design, the Board should require two modifications:

1. Given the importance of managing peaks on Hydro's IIS system, the Board should direct Hydro to maintain the "status quo" style demand charge of $12.00/kW, and with a resulting decrease primarily to the first block energy charge, as well as to a limited degree the winter second block energy charge.
2. The second block winter energy charge for the class should be reduced from the proposed level, in order to limit adverse impacts on customers who currently have a high load factor in winter (which is indicated to be the preferred customer load profile). The value can be derived from customer-specific analysis, which requires confidential information available to Hydro. While this

[128] IIC-NLH-027.

will slightly reduce the energy price signal in winter, it is necessary to prevent the rate from working at cross-purposes to the intended objective, which is to encourage higher load factors.

The Board should also require Hydro to clarify in the rate schedule that it will adjust the block boundary based on the number of days in the billing month, as Hydro indicated it will do in IIC-NLH-004.

Recommendation 13: In the event the Board decides it will approve the proposed rate design, the Board should require modifications, as outlined in this evidence, to maintain demand price signals and reduce adverse impacts on customers who currently have a high load factor in winter months.

6.0 SPECIFICALLY ASSIGNED CHARGES

SACs are a longstanding component of Hydro's rates for large customers, including industrials and NP[129]. The principle behind SACs is tied to the fact that most assets on Hydro's system are required to serve multiple customers, and these are treated as common costs, but certain individual assets are exceptions in that they are only required to serve a single customer. The costs associated with these single-customer assets, and related O&M, are recovered solely from the customer in question, through a fixed charge applied to their bills each month.

The SAC for the industrial customers are proposed to be adjusted from the existing level, as shown in Table 6.1:[130]

Table 6.1: Changes to Proposed Specifically Assigned Charges ($)

	Existing	2027 Test Year	*Change*
CBPP	13,311	5,822	*(7,489)*
Braya	107,678	103,152	*(4,526)*
Marathon	-	9,302	*9,302*
Teck	51,789	9,950	*(41,839)*
Vale	145,352	285,041	*139,689*

The derivation of the SAC for each customer is driven by the determination of which individual assets are to be specifically assigned. In response to IIC-NLH-29(h), Hydro confirmed that, other than "the addition of assets associated with the Valentine Gold Project near Star Lake", the following single line diagram prepared for the 2019 test year remains valid:[131]

[129] NP's SAC is not charged as a fixed amount, but is instead built into the second block rate charge, per Application, Vol 1, section 6.7.4, footnote 32.
[130] Application, Volume 1, section 6.7.4, pdf page 196 of 464.
[131] IIC-NLH-029 (h).

Figure 6.1: Single Line Diagram for SAC from 2017 GRA

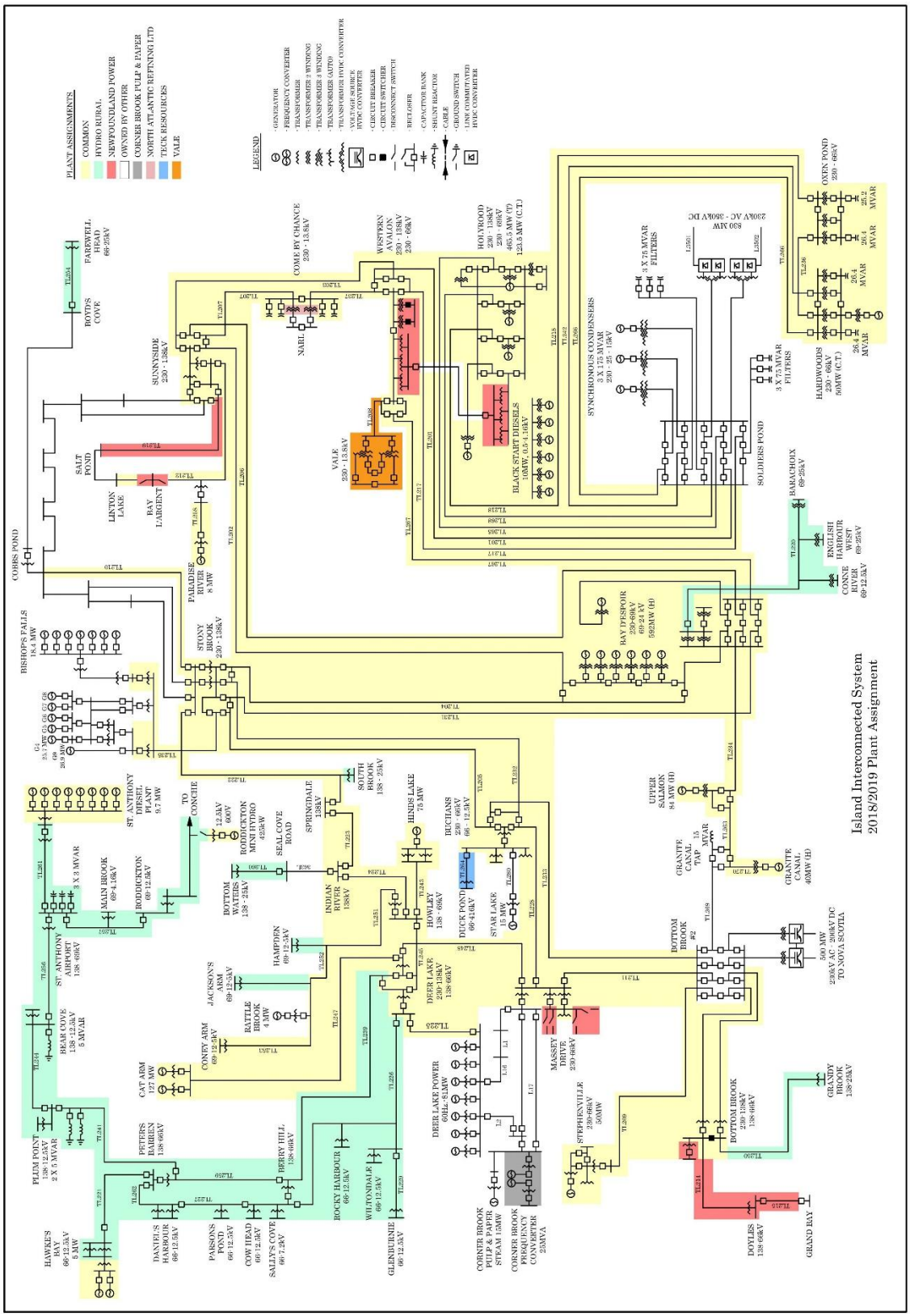


Figure 6.1 shows, through colored shading, the components of the system that were specifically assigned to each customer, and the components which were treated as common.

6.1 CHANGES TO SPECIFICALLY ASSIGNED CHARGES

In the current GRA, there are two material changes to the SACs affecting Island industrial customers. The first is the change to use an average of actual O&M expenses to set the O&M component of the SAC, rather than an allocated value from the COS study. This change was included as part of the 2025 negotiated settlement, and has been approved by the Board.[132] No issues have been identified with the implementation of this aspect of SACs.

The second change is the addition of material new assets to the parts of the system specifically assigned to Vale.

The assets specifically assigned to Vale, which are colored orange in Figure 6.1 comprise Transmission Line TL208, and the 230kV-13.8 kV substation at Long Harbour, as well as some limited assets related to termination of TL208 at the Western Avalon Termination Station (**"WAVTS"**). The majority of these assets were funded by a customer contribution from Vale, when Vale connected to the system in 2012. As of the 2013 General Rate Application, the total asset value not funded directly by Vale was only $0.389 million.[133]

For the 2019 Test Year, the total gross book value of assets not directly funded by Vale had increased to $0.504 million (NBV of $0.444 million).[134] This led to an annual SAC related to capital investment of only $0.038 million/year.[135]

In the current GRA, the annual charges proposed for Vale related to capital has increased more than 5 times, to $0.198 million/year, reflecting a forecast gross asset base of $2.749 million and a NBV of $2.197 million. As shown by Hydro's response to an RFI requesting that Hydro provide the list of asset investments since the last GRA that led to this material increase in the Vale specifically assigned book value, the vast majority of the asset additions are at WAVTS. The new net additions at WAVTS since the previous GRA total over $2.3 million in NBV, or $1.7 million net of new Vale contributions.[136]

The reason for such material spending at WAVTS, and the subsequent allocation of that spending to Vale, is not clear. In Vale's original connection in 2012, the total WAVTS capital costs considered to be specifically assigned to Vale totalled only $0.554 million ($0.384 million net of Vale contributions).[137] The new additions

[132] P.U. 14(2026)
[133] Per Undertaking 48 from the 2013 GRA, the total investment was $11,063,917 of which Vale contributed $10,674,903.
[134] IIC-NLH-029.
[135] The sum of return on debt, return on equity, and depreciation.
[136] IIC-NLH-029, Attachment 3.
[137] IIC-NLH-099 Attachment 1 Rev. 1 from the NLH 2013 GRA, page 4 of 6.

since the 2019 Test Year primarily consist of HV Cable, which appears to have been installed in 2018.[138] The specific assignment of this cable has no obvious justification based on any response to service requests from Vale, nor as an investment primarily driven by Vale requirements.

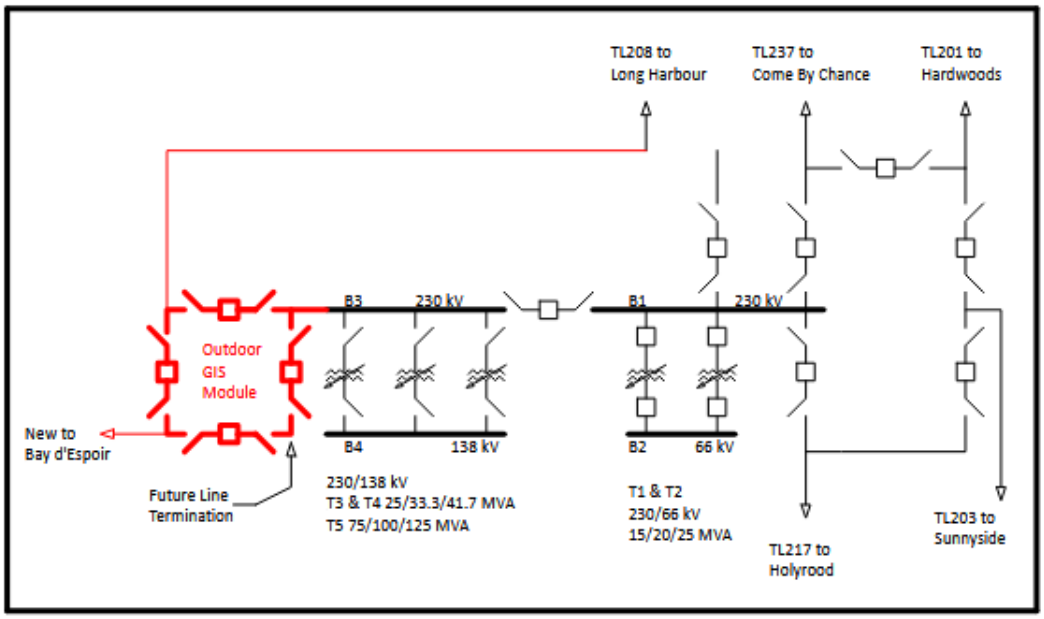
Instead, the spending appears to potentially be a component of the project to construct the new transmission line TL267 (BDE-WAV) approved by the Board in P.U. 53 (2014). In the Order approving TL267 BDE-WAV, the Board described the project as follows:[139]

> Hydro states that a new 230 kV transmission line between the Bay d'Espoir and Western Avalon terminal stations is required to reliably meet customer load growth on the Island Interconnected system. Hydro states that this requirement was identified in studies relating to the least cost long-term generation supply option for the Island Interconnected system.
>
> …
>
> The proposed 230 kV transmission line was required in both the isolated and Muskrat Falls interconnection scenarios: to facilitate new generation off the Avalon Peninsula in the isolated system scenario; and for system stability upon interconnection with Labrador.

In the capital expenditure application for TL267 (BDE-WAV) Hydro notes:[140]

> As part of the [gas insulated switchgear] ring bus addition, TL208 will be re-terminated in the new ring along with the new 230 kV transmission line to Bay d'Espoir. This will improve the reliability of the TL208 radial supply to Vale as it will no longer be tripped due to an outage to 230 kV bus B1 or 230/66 kV transformers T1 or T2. [The below figure] provides a single line diagram of the Western Avalon Terminal Station with the proposed additions shown in red.

[138] IIC-NLH-012, Attachment 2, Page 6, assets 447922-447926.
[139] P.U. 53 (2014), page 3.
[140] http://www.pub.nf.ca/applications/ARCHIVE/NLH2014Capital/NLHCBSUPP2014/TransmissionLine/Application/Application-2014-04-30.pdf pdf page 89 of 1794



The transmission capital application does not indicate that Vale service requirements were the genesis for or even a primary purpose of this project. Instead, it specifically indicates that the project is driven by common load growth on Avalon, and that an ancillary reliability benefit may accrue to Vale from the reconfiguration. Further, the point of a ring bus configuration is that it improves the reliability to all connections on the bus, not just a single transmission connection.

Assuming this assumption is correct – that the investment driving the increased SAC for Vale is the reconfiguration at WAVTS - the fundamental issue is whether the systemwide reliability benefits that all customers share, and are assigned common, should be treated differently than the benefits Vale receives, for which it alone will ultimately pay millions of dollars (through depreciation on the assets, plus return). In addition to imposing this specifically assigned cost on Vale, Vale will also shares in its proportionate allocation of the common asset base, which is increasing reliability to other customers.

The WAVTS spending is clearly not a replacement like-for-like with existing assets that have been previously determined to be directly related to Vale. The full record necessary to conclusively determine whether any of the new and reconfigured WAVTS assets should be specifically assigned to Vale is not available, as despite two rounds of RFIs, Hydro has failed to fully disclose the nature of the assets. In particular, in IIC-NLH-012 (a) Hydro states that the changes to SAC from 2019 to 2026 are "not material" despite the assets assigned to Vale increasing fivefold. In the second round of RFIs, the specific list of the new assets assigned to Vale were disclosed, but only with granular and technical names (e.g., "447925: TL 208 HV CABLE ?C WAV TS" as per IIC-NLH-029 Attachment 2) that do not disclose the nature of the investment, the purpose of the investment, or the function in serving Vale.

Further, the 2018 "Review of Industrial Customer Specifically Assigned Assets" (**"2018 SAC Review"**)[141] conducted by Hydro explicitly notes:[142]

> It should be noted that in 2018, once TL 208 is moved to the new gas insulated ring bus, which is a common asset, B1L08 will be retired, and therefore there will be no additional reassignment to Vale for these three items.

Despite the 2018 SAC Review stating that once the ring bus is in place, it will be a common asset and there would be no assignment to Vale, Hydro appears to be taking the opposite position in the current GRA, by specifically assigning the costs associated with this component of the project to Vale.

The 2018 SAC Review document goes on to say:[143]

> **4.0 Future Monitoring of Specifically Assigned Expenditures**
>
> During the proceedings for Hydro's 2018 Capital Budget Application, the Island Industrial Customers expressed concern with the lack of communication between Hydro and the individual customers regarding capital projects that would impact specifically assigned charges. In Hydro's final submissions for the 2018 Capital Budget Application, Hydro recognized the concerns raised by the Island Industrial Customers and Hydro committed to engage further with the individual customers on this matter.
>
> Hydro believes this engagement should include discussions with the affected customers on the selection criteria for specifically assigned assets, and what assets are assigned to the individual members. As well, Hydro is committed to clearly identifying capital expenditures that it will be proposing be specifically assigned in advance with each customer, as well as in specific project proposals in all future capital budget applications.

It is not apparent that any disclosure was made in regulatory filings to date (including the two rounds of RFIs) that the ring bus assets are now intended to be specifically assigned to Vale. Further, the version of the 2018 SAC Review filed with the current GRA RFIs redacts the customer-specific single line diagrams, so it is difficult to conclusively determine what was intended with respect to the specific ring bus component changes.[144]

[141] Filed in IIC-NLH-029 Attachment 5
[142] IIC-NLH-029 Attachment 5, page 5.
[143] IIC-NLH-029 Attachment 5, pages 6-7.
[144] A version with the SLD was filed with the 2017 GRA:

The additions at WAVTS completed since the 2019 Test Year should not be specifically assigned to Vale unless Hydro can establish that:

1. The assets are directly and solely related to service to Vale via TL208;
2. The addition of the assets was driven primarily by Vale's service requirements; and,
3. The assets are distinct from the ring bus assets indicated to be a common asset in the 2018 SAC Review.

Effectively, absent clear and compelling evidence from Hydro that the addition of the assets in question are directly and solely related to service to Vale, were driven primarily by Vale's service requirements, and are in some way different than the ring bus assets indicated to be a common asset in the 2018 SAC Review, the additions at WAVTS since the 2019 Test Year should not be specifically assigned to Vale.

Recommendation 14: The additions at the Western Avalon Terminal Station completed since the 2019 Test Year should not be specifically assigned to Vale unless Hydro can establish that:

1. **The assets are directly and solely related to service to Vale via TL208;**
2. **The addition of the assets was driven primarily by Vale's service requirements; and,**
3. **The assets are distinct from the ring bus assets indicated to be a common asset in the 2018 SAC Review.**

6.2 CONTINUED SPECIFIC ASSIGNMENT OF THE LONG HARBOUR TRANSMISSION TL 208 AND TERMINAL STATION

The configuration of assets serving the Long Harbour substation (also known as the Voisey's Bay Nickel (**"VBN"**) substation) have been specifically assigned to Vale since being constructed in 2012.

This practice has been implemented despite the assets not generally meeting the test for specific assignment. Notably, assets are to be specifically assigned when they meet the test set out in the industrial

http://www.pub.nf.ca/applications/2017/nlh2017gra/report/From%20NLH%20-%20Review%20of%20Industrial%20Customer%20Specifically%20Assigned%20Assets%20Report%20-%20Revision%201%20-%202018-03-05.PDF However, that version only includes the old configuration (pdf page 36), not the new ring bus configuration. Regardless, it makes clear that prior to the new ring bus, it is only the minimal assets downstream of the TL 208 switch, which are only relevant to supply to TL 208 and cannot be used to serve other customers, that are considered for SAC.

contracts (including the Vale contract) as follows: "that equipment and those facilities which are owned by Hydro and used to serve the Customer only."[145] This is consistent with the definition in the GRA, which defines specifically assigned assets as follows: "any transmission facilities specific to providing service to a single Industrial customer."[146]

In the case of Long Harbour, the TL 208 and VBN substations do not only serve one customer. Both Vale and Linde operate as unique and separate customers receiving electrical service through these assets. In response to an RFI asking why this asset remains specifically assigned, Hydro replied: "For the purpose of asset assignment, the VBN Terminal Station and TL 208 serve only Vale. This remains unchanged since its initial assignment and its assignment in Hydro's 2017 GRA."[147]

This answer from Hydro is not entirely correct, in that the Linde loads are also served by the VBN station and TL 208. In other words, the TL208 assets do not only serve one customer. The configuration was explained in RFIs at the time of the original connection to Praxair (the former owner of the Linde assets) was reviewed before the Board in 2013. Specifically, NP-NLH-6 from that proceeding noted:

> The energy and demand usage for use in billing Vale will be determined by subtracting the metered energy and demand usage of Praxair from the total VBN terminal station metered energy and demand.
>
> This metering arrangement is unique among Hydro's Industrial Customers in order to minimize metering costs.

Hydro further noted:[148]

> Praxair is not supplied from Vale's distribution system. It is directly connected to the low voltage bus on the secondary side of the 230 kV terminal station transformers. As indicated in the single line drawings provided in Hydro's response to NP-NLH-1, Praxair will be connected to feeder lines originating at the two 13,800 V busses in the Vale substation
>
> …
>
> Praxair is directly supplied from the bulk transmission system from a transformer with a primary side voltage of 230 kV and therefore meets the definition of an Industrial Customer in the same manner that Vale is an Industrial Customer.

[145] PUB-NLH-047, Attachment 2, page 3, section 1.01 (w).
[146] Application, Volume 1, section 6.7.4; pdf page 195 of 464.
[147] IIC-NLH-029 (j).
[148] NP-NLH-3 and NP-NLH-4 from the 2013 Praxair Service Agreement proceeding.

While it has been accepted that TL208 and related assets were specifically assigned to Vale, it appears appropriate to investigate if this treatment remains valid given the passage of time and changes in the relationships between the parties. Clearly, Praxair no longer owns the assets, as they have been transferred as part of a commercial transaction to Linde. Given the time that has passed since this determination was made (almost 20 years by the time of the next GRA), it bears revisiting the commercial arrangement between Vale and Praxair/Linde to determine if the justification for the direct assignment to Vale still exists. For example, the specific assignment to Vale may have been justified in 2012 if the only operations of Praxair, and the only customer it serves, is Vale itself. If Linde is instead a producer selling to more than solely Vale, it would not be appropriate to maintain the specific allocation to Vale to pay for assets that serve both companies. In that case, the assets would more appropriately be considered common.

It is acknowledged that the 2019 COS settlement agreement provides that the then-current specific assignment of assets would be maintained for the current GRA, as follows:[149]

> 14. The Parties agree that the transmission assets currently specifically assigned to customers continue to be specifically assigned.

It would be appropriate for a review to be undertaken, in preparing for the next GRA, as to whether it remains a valid approach to specifically assign the entire TL208 and related assets to Vale.

Recommendation 15: For the next GRA, Hydro should consider the physical arrangement and commercial nature of Linde's operations in order to determine if the TL 208 and Long Harbour substation assets should now be considered common, on the basis of the assets serving multiple distinct and commercially independent customers.

[149] 2019 COS settlement: http://www.pub.nf.ca/applications/2018/NLH2018CostofService/settlement/Settlement%20Agreement%20-%202019-10-04.PDF

APPENDIX A:

RESUME

PATRICK BOWMAN

Principal Consultant
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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 Manitoba Industrial Power Users Group (2020 – present; previous involvement since 1998): 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 (2020 – present; previous involvement since 2001): Prepare analysis and evidence for Newfoundland Hydro GRA and other rate hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

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

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 Industrial Group of Nova Scotia Power Inc. (2024-present): Technical support to Cost of Service working group and negotiations on methodology, provide evidence on Energy Efficiency metrics, industrial customer rate design.

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 Government of Canada (2025-present): Act as expert witness in litigation regarding valuation of historic hydro-generation development.

For the Office of the Utilities Consumer Advocate of Alberta (2024-present; previous involvement 2016-2024): 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 City of Langford (2024-2026): Assistance in development of alternatives for renegotiation of sewer services supply agreement.

For Nelson Hydro (2020-2025; with previous involvement since 2013): 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 Industrial Gas Users Association of Manitoba (2020 – 2025): Support for cost of service and rate design matters. Testimony before the Manitoba Public Utilities Board.

For the PEI Federation of Agriculture (2023-2025): Support in regulatory review of Maritime Electric Rate Design proceeding.

For Yukon Energy Corporation (2024-2025): Provide analysis regarding net salvage regulatory account options.

For the Ontario Energy Board (OEB) (2025): Act as facilitator for distribution rate application for Welland Hydro.

For Vale Newfoundland (2022-2024): Advice regarding negotiations on electrification and interruptible power framework.

For a law firm representing the Government of Alberta (2024): Assistance in calculation of depreciation rates for the purposes of property taxation of industrial property.

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

INTERGROUP CONSULTANTS LTD., WINNIPEG, MANITOBA
1998 – 2024 – 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 the Ontario Energy Board (OEB) (2024): 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 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, depreciation, net salvage, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers.

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

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
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
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

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Efficiency Manitoba	3 yesar Energy Efficiency Plan Review	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2019	Yes
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
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	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

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
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	2023-24 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 Settlement
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
New Brunswick Power	Matter 554 - Class Cost Allocation Study Methodology Review	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2024	Yes
Maritime Electric	UE22503 Rate Design	Analysis, Preparation of Intervenor Evidence	Prince Edward Island Regulatory and Appeals Commission (IRAC)	PEI Federation of Agriculture	2024-2025	Yes
Nova Scotia Power	M11475 Cost of Service Study	Analysis, Support of Intervenor position	Nova Scotia Energy Board (NSEB)	Industrial Group (IG)	2024-2026	No
Naka Power (NWT)	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	NWT PUB	NTPC	2025	Yes
NTPC	2024-25 and 2025-26 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2025	Yes
Centra Gas Manitoba	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	MPUB	IGU	2025	Yes
Fortis BC	2025 Cost of Service and Revenue Rebalancing	Analysis, Support of Intervenor position	BCUC	BC Municipal Electrical Utilities	2025	No
Efficiency One	M12228 Benefit-Cost Test	Analysis, Preparation of Intervenor Evidence	NSEB	Industrial Group (IG)	2025	Yes
Nova Scotia Power	2025 GRA	Analysis, Support of Intervenor position	NSEB	Industrial Group (IG)	2025-2026	No
AltaLink Management Ltd.	2026-27 General Tariff Application	Analysis, Support of Consumer Advocate in Negotiation Process, Preparation of Intervenor Evidence on Depreciation .	AUC	UCA	2025-2026	Yes
Manitoba Hydro	2025-26 to 2027-28 GRA	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2025-2026	Yes
Manitoba Hydro	2026-2035 Integrated Resource Plan	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2026	Yes
ATCO Electric Transmission	2026-2027 GTA Depreciation	Analysis, Support of Consumer Advocate in Negotiation Process, Preparation of Intervenor Evidence on Depreciation .	AUC	UCA	2026	No
Eastward Energy	2026 General Rate Application	Analysis, Preparation of Intervenor Evidence	NSEB	Michelin/Dalhousie	2026	No
Nova Scotia Power	Extra Large Industrial Demand (ELID) Rate	Analysis, Preparation of Intervenor Evidence	NSEB	Industrial Group (IG)	2025-2026	Yes
New Brunswick Power	Matter EL-002-2026 Rate Design Part II	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2026	Yes