BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NEWFOUNDLAND AND LABRADOR HYDRO

2026 GENERAL RATE APPLICATION

Cost of Service and Rate Design Matters

Evidence Prepared By

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On Behalf of

The Consumer Advocate

November 2, 2026

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1.1 Purpose and Scope of Evidence

The principal focus of this evidence is the translation of Hydro's 2027 Cost of Service ("COS") Study results into class revenue requirements and rates that are fair, equitable and reasonable. While the COS Study provides an important analytical foundation for rate setting, its resulting class cost allocations and revenue-to-cost coverage ratios ("RCCs") do not, in themselves, determine the appropriate rates to be charged to each customer class. That determination requires the exercise of regulatory judgment, informed by cost causation as well as other relevant ratemaking considerations, including fairness and equity, rate stability and the broader consequences of interclass rate adjustments.

This evidence does not seek to reopen or relitigate previously approved COS methodologies in the current GRA, except to the extent that specific methodological matters remain outstanding for determination. Rather, the examination of COS methodology undertaken in this evidence is expressly for the purpose of evaluating the interpretation and application of the resulting class cost allocations and RCCs in rate design.

This distinction is particularly important given the fundamental transformation of Hydro's generation and transmission system following the integration of Muskrat Falls and associated infrastructure. This transformation of NLH’s system has resulted in significant shifts in the composition of Hydro's costs, away from historical fuel and energy-related costs toward long-lived, capital-intensive generation and transmission investments, has materially changed the costs being allocated among customer classes. Accordingly, the application of previously approved methodologies have produced materially different class cost responsibilities, without necessarily establishing that the resulting RCCs should be translated directly into corresponding interclass rate adjustments.

In my view, these circumstances warrant caution in relying on the precise COS results to implement substantial interclass rate realignment in the 2027 Test Year. They also warrant a targeted review of Hydro's generation and transmission COS methodologies, including the treatment and allocation of export revenues, in advance of the next GRA. Such a review is recommended prospectively and is distinct from the rate-setting determinations requested in the current proceeding.

1.2 Summary of Recommendations

Based on the analysis presented in this evidence, the following recommendations are provided for the Board's consideration:

1. **Classification of Wind Generation Costs (Section 4.6)**

   The Board should deny Hydro's proposed change in the classification of wind power purchase costs from 22% demand and 78% energy to 43% demand and 57% energy for the 2027 COS Study. The currently approved classification should be retained pending a more comprehensive assessment of the appropriate methodology.

   NLH should undertake a comparative assessment of alternative wind generation classification methodologies in advance of its next comprehensive COS Study or GRA, including the relationship between marginal Effective Load Carrying Capability (ELCC) and the classification of total purchase costs, with quantified implications for class cost responsibilities.

2. **Classification of Holyrood Costs (Section 4.7)**

   The existing methodology for classifying Holyrood's non-fuel production costs should be retained for the 2027 Test Year.

   NLH should undertake a comparative assessment of alternative classification methodologies, including the existing capacity-factor methodology, System Load Factor (SLF) and unit-specific approaches, in advance of its next comprehensive COS Study or GRA.

3. **Interpretation of COS Results and Revenue-to-Cost Coverage Ratios (Section 5)**

   It is recommended the Board recognize that the achievement of an RCC of precisely 1.00 is not, in itself, determinative of fair, equitable and reasonable class rates.

   In evaluating class revenue responsibilities, it is recommended the Board:

   - Recognize the appropriateness of applying a range of reasonableness around RCC unity, without prescribing a specific numerical range in this proceeding;
   - Consider both the dollar and proportional consequences of alternative COS methodologies and allocation assumptions for all materially affected customer classes; and
   - Consider the implications of changing class loads, long-lived infrastructure costs and the potential redistribution of cost responsibilities among customer classes when assessing interclass equity.

4. Proposed Island Industrial Rate Adjustment (Sections 6 and 7)

It is recommended the Board consider an alternative under which Island Industrial customers receive an overall rate increase of 2.25% for 2027, rather than NLH's proposed 14.3% reduction.

This alternative would result in approximately $8.5 million being available to reduce amounts otherwise recovered from Newfoundland Power and Rural Island Interconnected customers under Hydro's proposal.

NLH should be directed to propose the appropriate treatment of these revenues in establishing class rates, consistent with the applicable rate mitigation framework.

5. Future Review of Cost-of-Service Methodologies (Sections 4 and 7.3)

A further review of Hydro's COS methodologies, focused on the classification and allocation of generation and transmission costs and the treatment of export revenues, will likely be warranted as operating experience with the interconnected system develops.

Such a review should be considered prior to or in conjunction with Hydro's next GRA and should include an assessment of reasonable alternative methodologies and their quantified implications for class cost responsibilities.

2.0 Overview of Qualifications and Duties to the PUB

2.1 Qualifications and Relevant Regulatory Experience

Through a joint regulation consulting practice with Mr. Darren Rainkie, CPA, CBV, Mr. Rainkie and Ms. Derksen provide services to a wide range of clients that participate in and are impacted by rate-regulation and regulatory proceedings. In this proceeding, Ms. Derksen is providing evidence for the Consumer Advocate ("CA").

Ms. Derksen has over 30 years of hands on and multi-faceted expertise in energy regulation and ratemaking, with demonstrated experience providing clients with advice that is theoretically sound, practical, and sustainable. She specializes in providing public utility regulatory services to clients, with an emphasis on utility ratemaking philosophy, cost of service and rate design matters.

Ms. Derksen has a deep specialization in utility ratemaking, progressively taking on more senior responsibilities from regulatory to rate analyst, to managerial roles with Manitoba Hydro and Centra Gas, and since 2018, as an independent expert utility ratemaking consultant.

Her experience relevant to the evidence provided in this proceeding includes senior level public utility experience (as a former Manager, Gas Regulation between 2005 and 2008 and Manager of Cost of Service & Rates from 2008 to 2017), developing ratemaking objectives and regulatory strategy, leading cost of service study methodological reviews, directing the preparation of electric cost of service studies and rate design proposals and translation of overall revenue requirements into class revenue requirements and rates, consistent with corporate rate strategy.

Since 2018, Ms. Derksen has provided client advice in a number of Canadian jurisdictions on a variety of topics with themes consistent with NLH's current GRA including inter-company cost allocation, the rate consequences of large capital additions, rate policy related to decarbonization, marginal cost-based ratemaking, and customer contribution policy to name a few.

In this regulatory proceeding, Ms. Derksen will lead the evaluation of NLH's cost of service and rate design proposals, its Load forecast and Export Revenue and preparation of evidence on behalf of the Consumer Advocate. Ms. Derksen has testified before public utility tribunals on numerous occasions over the last three decades, as an independent expert witness and previously as a rate policy and subject matter witness for MH. This is Ms. Derksen's first appearance before the Public Utilities Board in Newfoundland. Ms. Derksen's full curriculum vitae is provided as a attachment to this Evidence.

2.2 Duties to the PUB and Independence

Ms. Derksen acknowledges that she has a duty to provide independent evidence that is fair, objective and non-partisan, related only to matters within her areas of expertise and to provide such additional assistance as the PUB may reasonably require to determine issues.

This duty is owed to the Public Utilities Board, not to the Consumer Advocate (or member organizations) or legal counsel.

2.3 Organization of Evidence

The following Sections are included in this Evidence:

Section 1.0: Introduction & Purpose

Section 2.0: Qualifications and duties to the PUB

Section 3.0: Regulatory context and application

Section 4.0: Evaluation of the 2027 COS Study

Section 5.0: The 2027 RCCs Should Inform, Not Dictate, Interclass Rate Realignment

Section 6.0: Hydro's Rate Design and Mitigation Proposals Demonstrate the Limits of COS Results in Determining Rates

Section 7.0: NLH's Proposed Class Rate Adjustments Warrant Reconsideration

3.0 Introduction & Overview of Hydro's 2026 GRA and Phase II Matters

3.1 Regulatory Context and Matters Before the Board

Newfoundland and Labrador Hydro's ("NLH" or "Hydro") 2026 General Rate Application ("GRA") is its first GRA since the 2017 GRA, which established rates based on the 2019 Test Year. Since that time, significant changes have occurred in Hydro's electrical system, cost structure and the policy framework governing the recovery of costs from customers.

Most notably, the Muskrat Falls Generating Station and Labrador Transmission Assets were commissioned in November 2021, followed by the Labrador-Island Link in April 2023. The addition and commissioning of these facilities fundamentally changed Hydro's sources of supply and the costs associated with serving customers on the Island Interconnected System and have fundamental implications to the allocation of costs between (inter) and within (intra) customer classes.

Recognizing the significant rate impacts associated with recovery of these costs, the Provincial Government introduced a series of rate mitigation measures. In May 2024, the Government finalized its Rate Mitigation Plan and issued Order in Council OC2024-062 pursuant to subsection 39(3) of the Hydro Corporation Act, 2007. The Order directs Hydro to structure its rate applications through 2030 such that annual retail rate increases attributable to NLH's costs for domestic customers are targeted at 2.25%, with increases for other Island Interconnected customers to be established in a compatible manner. The Order directed Hydro to fund the additional mitigation required through its own sources, to the extent possible.

Consequently, Hydro's 2026 GRA, for purposes of Cost Allocation and Rate Design phases of the ratemaking process is being considered within a framework in which the costs of providing service have not only increased substantially, with the increases being muted for customers constrained by Government's rate mitigation policy, but also the nature and types of costs incurred to serve customers has fundamentally changed. This latter matter of the nature and types of cost changes has profound consequences to the sharing of costs between customer classes.

In anticipation of the inclusion of Muskrat Falls supply costs in customer rates, Hydro undertook a review of its Cost of Service ("COS") methodology, filing an application with the Board of Commissioners of Public Utilities ("Board") on November 15, 2018. The purpose of the review was to consider revisions to the methodologies used to functionalize, classify and allocate costs among customer classes, including the treatment of Muskrat Falls supply costs following full commissioning of the Project.

The 2018 COS Methodology Review resulted in a negotiated Settlement Agreement filed October 4, 2019, which was approved by the Board in Order P.U. 37(2019). The settlement established agreed methodologies for use in the first GRA incorporating Muskrat Falls Project costs, subject to further consideration of certain identified matters. The agreement

also contemplated that a subsequent COS Methodology Review could be undertaken upon request of a party and approval by the Board.

On August 22, 2025, Hydro filed a further COS Methodology Application addressing outstanding matters from the earlier review and proposing modifications to certain existing methodologies. The review considered the continued appropriateness of selected functionalization, classification and cost allocation methodologies in light of changes to Hydro's system and operating circumstances.

Following a technical conference in October 2025 and subsequent negotiations, the parties reached a Settlement Agreement dated May 15, 2026. The agreement was approved by the Board in Order P.U. 14(2026). The settlement addressed the majority of Hydro's proposed methodological changes, while leaving certain matters for consideration in the current GRA.

Two matters were expressly deferred to the 2026 GRA: the classification of Holyrood Thermal Generating Station generation and fuel costs, and the generation credit provided to Newfoundland Power, including Hydro's proposed 64 MW hydraulic generation credit.

In addition, Hydro has introduced a proposal in the current GRA to revise the classification of wind generation purchases from 22% demand and 78% energy to 43% demand and 57% energy. It appears this matter was not considered in the 2025 COS Methodology proceeding because the supporting Effective Load Carrying Capability study had not been completed.

Accordingly, the COS study supporting Hydro's 2026 GRA incorporates methodologies settled and approved through Orders P.U. 37(2019) and P.U. 14(2026), together with additional methodological proposals advanced for consideration in this proceeding.

3.2 Overview of NLH's 2026 GRA

Hydro's proposed 2027 Test Year revenue requirement, before rate mitigation, is approximately $1,299.7 million, compared with $643.0 million for the 2019 Test Year, an increase of $656.7 million, or approximately 102.1%. The proposed 2027 revenue requirement includes $780.4 million in Muskrat Falls supply costs, partially offset by reductions in fuel costs and other changes in Hydro's cost structure.

The proposed 2027 revenue requirement is reduced by $502.0 million in rate mitigation funding, resulting in a net revenue requirement of $797.7 million to be recovered through customer rates. After incorporating rate mitigation, Hydro's revenue requirement has increased by $154.7 million, or approximately 24.1%, relative to the 2019 Test Year

Hydro's proposed rates for the 2027 Test Year reflect differing adjustments among customer classes. In accordance with the Provincial Government's rate mitigation direction, Hydro is proposing a 2.25% increase in rates for Island Domestic customers, while proposing a decrease of approximately 14.3% for Island Industrial customers. These differing rate adjustments reflect the combined effects of Hydro's COS results, rate mitigation

arrangements and proposed rate design. The implications for the relative recovery of costs among customer classes are examined in subsequent sections of this evidence.

The proposed 2027 revenue requirement reflects fundamental changes in Hydro's underlying cost structure, including:

- The addition of $780.4 million in Muskrat Falls supply costs;
- $502.0 million in rate mitigation funding, applied as a reduction to revenue requirement;
- Fuel costs significantly declining by approximately $113.6 million, from $219.9 million in the 2019 Test Year to $106.3 million in the 2027 Test Year; and
- A fundamental change in the composition of generation-related costs, from fuel-intensive thermal generation toward predominantly fixed supply costs, with implications for the classification and allocation of costs among customer classes.

Absent rate mitigation funding, Hydro's forecast 2027 costs to serve customers total approximately $1,299.7 million. The proposed rate mitigation funding therefore reduces the amount to be recovered through customer rates by approximately 38.6%.

In addition to approval of its revenue requirement, Hydro seeks approval of its 2027 COS study and associated rate design proposals, including the allocation of costs among customer classes, the treatment of rate mitigation funding, export revenue, and proposed changes to certain cost allocation methodologies.

Other cost allocation changes proposed by NLH as part of its 2026 GRA include the proposed treatment of Holyrood costs, Newfoundland Power's generation credit, and the classification of wind generation purchases.

It is also significant that Hydro's proposed 2027 rates are designed to recover the class revenue requirements established directly from its 2027 Cost of Service Study (subject to the Rural Deficit allocation framework). In effect, Hydro's proposed rates directly align the class cost responsibilities determined by its 2027 COS Study (i.e. revenues and costs are set at unity), without a separate assessment of whether those allocations provide an appropriate basis for establishing the relative revenue responsibilities of customer classes. For Island and Labrador Industrial customers, Hydro explicitly targets revenue-to-cost coverage ratios (RCCs) of 1.00. For Newfoundland Power, the reported RCC is 1.11 before the assignment of its share of the Rural Deficit; however, forecast revenues are approximately equal to total assigned costs once that responsibility is included. Consequently, the proposed rates substantially implement the class revenue responsibilities resulting from Hydro's COS methodology, making the reasonableness of the underlying cost allocations particularly consequential.

Hydro is also proposing to phase in rate increases for Rural Labrador Interconnected customers at an average of 2.25% annually over the 2027–2030 period, with the associated revenue deficiencies deferred for future recovery.

Hydro's resulting RCCs by Class flowing from the 2027 Cost of Service Study and its proposed rates are shown in the Figure below:

Figure 1: Comparison of Revenue-to-Cost Coverage Ratios by Customer Class[1]

Customer class	2019 TY	2027 Unmitigated	2027 Mitigated	2027 Mitigated — Adjusted
Newfoundland Power	1.14	1.09	1.11	1.00[2]
Island Industrial	1.00	1.00	1.00	1.00
Labrador Industrial	1.00	1.00	1.00	1.00
Rural Lab Interconnected[3]	1.14	1.09	1.11	1.00[4]
Rural Island Interconnected	0.70	0.58	0.79	0.79
Island Isolated	0.15	0.17	0.17	0.17
Labrador Isolated	0.24	0.27	0.27	0.27
L'Anse-au-Loup	0.42	0.42	0.42	0.42

These matters are examined in the following sections of this evidence, with particular attention to the implications of Hydro's COS methodologies and rate design proposals for the reasonableness and equity of rates among customer classes.

[1] RFI NLH - CA 117, Figure 1, page 2; 2027 COS Study, Schedules F.1.2 and G.1.2

[2] NP:

Forecast revenues	$636.812
Less: Rural Deficit allocation	($62.779)
Adjusted revenues	$574.033
Allocated costs excluding Rural Deficit	$574.037
Adjusted RCC	1.00

[3] Hydro proposes to phase in rate increases for Rural Lab Interconnected customers at 2.25% annually over 2027–2030, with associated unrecovered supply costs deferred. The reported RCCs are COS Study results, not projected annual phase-in RCCs.

[4] Rural Lab Interconnected:

Forecast revenues	$22.231
Allocated costs before Rural Deficit	$20.039
Rural Deficit allocation	$2.192
Total assigned costs after allocation	$22.231
Hydro's reported RCC	1.11
Adjusted RCC, excl the deficit allocation from rev and costs	1.00

4.0 Evaluation of the 2027 COS Study

As discussed in Section 1.0 of this evidence, the examination of COS methodologies in this section is undertaken principally to assess the significance of methodological assumptions and their implications for interpreting the 2027 class cost allocations and RCCs for rate-setting purposes. Except for matters expressly outstanding in this GRA, the analysis is not intended to seek reconsideration of previously approved methodologies in this proceeding.

4.1 Muskrat Falls Has Fundamentally Changed the Costs and Benefits of Island Supply

The commissioning of the Muskrat Falls Project represents a transformational change in Newfoundland and Labrador Hydro's electricity supply system. Historically, the Island Interconnected System operated largely in isolation, relying primarily on generation resources located on the Island to meet its electricity requirements. Holyrood Thermal Generating Station was an important source of both energy and capacity, and fuel expenditures represented a substantial component of Hydro's production costs. With the commissioning of Muskrat Falls and the Labrador-Island Link ("LIL"), the Island system is now interconnected, providing access to substantial hydroelectric generation located outside the Island and opportunities for electricity exchanges with other jurisdictions.

This transformation has materially changed the composition of Hydro's supply costs. A significant portion of fuel-related expenditures has been replaced by substantial fixed contractual costs associated with Muskrat Falls generation and transmission, characteristic of large-scale hydroelectric infrastructure. The introduction of Muskrat Falls has reduced Hydro's reliance on thermal generation and associated fuel expenditures, substituting significant long-term generation and transmission commitments whose costs do not vary directly with annual electricity consumption. This paradigm shift has profound implications for cost of service ("COS"), as the methodologies used to classify costs between demand and energy, and subsequently allocate them among customer classes, now apply to a substantially different and much larger portfolio of supply costs.

For the 2027 Test Year, Hydro forecasts Muskrat Falls-related supply costs of approximately $780.4 million and fuel costs of $106.3 million. By comparison, fuel costs were approximately $219.9 million in the 2019 Test Year. The $113.6 million reduction in fuel expenditures, together with the introduction of substantial Muskrat Falls supply costs, illustrates the magnitude of the change in Hydro's underlying supply cost structure.

Implications for Cost Classification

Generation resources are developed and maintained to satisfy different system requirements, including dependable capacity, energy supply and reliability. These requirements are interrelated, and individual resources frequently provide more than one benefit. Resources with high capital costs and relatively low variable operating costs frequently supply substantial quantities of energy, while resources with lower capital costs

but higher operating costs may be maintained principally to satisfy peak demands, contingencies or reliability requirements.

Accordingly, the classification of generation costs requires consideration of the functions and benefits of the particular resource, rather than relying solely on the fixed or variable nature of its expenditures. Although the costs of capital-intensive hydroelectric generation are predominantly fixed, this does not necessarily establish that those costs are demand-related. The underlying system requirements that the investment was intended to satisfy are also relevant to assessing cost causation.

Based on the project rationale discussed in the available record, Muskrat Falls was intended to provide domestic capacity and energy, reduce reliance on oil-fired generation, support future load requirements and establish opportunities for electricity exchanges and exports. These multiple objectives are relevant to understanding the functions and benefits of the investment for COS purposes.

The distinction between cost characteristics and cost causation is particularly important where a capital-intensive generation resource replaces substantial energy-related expenditures. Holyrood fuel expenditures, for example, are classified entirely as energy-related, whereas Muskrat Falls generation and associated transmission costs are classified between demand and energy. Consequently, the replacement of historical supply costs with Muskrat Falls costs has implications not only for the magnitude of Hydro's revenue requirement but for purposes of this Evidence, for the distribution of costs among customer classes.

Development of the Approved Muskrat Falls Classification Methodology

In November 2018, Hydro proposed revisions to its COS methodology to accommodate the Muskrat Falls Project. Its original proposal employed an equivalent-peaker approach that would have classified approximately 20% of applicable Project costs as demand-related and 80% as energy-related.

The subsequent settlement, approved in Order P.U. 37(2019), instead adopted the System Load Factor ("SLF") methodology for classifying Muskrat Falls generation costs and the associated LIL and Labrador Transmission Assets. Under this methodology, the applicable costs are functionalized as production and classified between demand and energy based on the system load factor. For the 2027 Test Year, this produces a classification of 49.71% demand and 50.29% energy.

In my experience, SLF is an established methodology used to classify generation-related costs at other electric utilities, including Manitoba Hydro, which also operates a predominantly hydroelectric generation system. SLF is one of several recognized classification approaches and provides a relatively straightforward means of attributing generation costs between demand and energy. However, it represents an approximation of

the relative demand and energy responsibilities associated with generation resources, rather than a precise determination of the underlying economic responsibility for the investment.

The adoption of SLF therefore reflects a methodological judgment regarding the attribution of Muskrat Falls costs to demand and energy requirements. Its approval does not necessarily establish that the underlying economic responsibility for those costs is divided in precisely the same proportions.

In fact, in 2004 National Economic Research Associates (NERA) examined alternative generation classification approaches for Manitoba Hydro[5], including, for example the SLF. NERA identified limitations associated with SLF including its failure to reflect incremental costs or market conditions and emphasised that the implications of classification methodologies depend upon the accompanying allocation methods, the treatment of transmission costs, and export revenues.

A subsequent settlement, approved in Order P.U. 14(2026), addressed the classification and allocation of rate mitigation funding and other offsets. It did not replace the previously approved SLF methodology for Muskrat Falls costs. These approved methodologies underpin Hydro's 2027 COS Study.

Implications for Class Cost Responsibilities

The costs allocated to individual customer classes reflect two distinct considerations: the proportion of costs classified as demand-related or energy-related, and each class's relative share of the applicable demand and energy allocation factors.

This interaction is particularly important given the substantially different demand and energy characteristics of Newfoundland Power and Island Industrial customers. A change in the classification of a significant pool of generation costs can therefore affect the relative cost responsibilities assigned to these classes, even where the underlying total revenue requirement remains unchanged.

The approved SLF methodology provides the basis for Hydro's proposed 2027 COS allocations. However, the resulting class cost responsibilities must be understood in the context of the fundamental transformation of Hydro's supply system and the methodological judgments underlying the classification of its costs. These considerations do not, in themselves, establish that the approved methodology is inappropriate, but they are relevant to assessing the degree of precision that should be attributed to the resulting class cost allocations.

[5] National Economic Research Associates (NERA), Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies, prepared for Manitoba Hydro, February 11, 2004.

4.2 Muskrat Falls Has Materially Changed the Distribution of Costs Among Classes flowing from the 2027 COS Study

For the 2027 Test Year, NLH forecasts approximately $780.4 million in Muskrat Falls-related supply costs and $106.3 million in fuel costs. By comparison, fuel costs have decline significantly from approximately $219.9 million in the 2019 Test Year[6].

The reduction of approximately $113.6 million in fuel expenditures, together with the introduction of substantial Muskrat Falls costs, illustrates the magnitude of the transformation.

The effect of this change is apparent in class allocated costs between the 2019 and 2027 Test Years[7]:

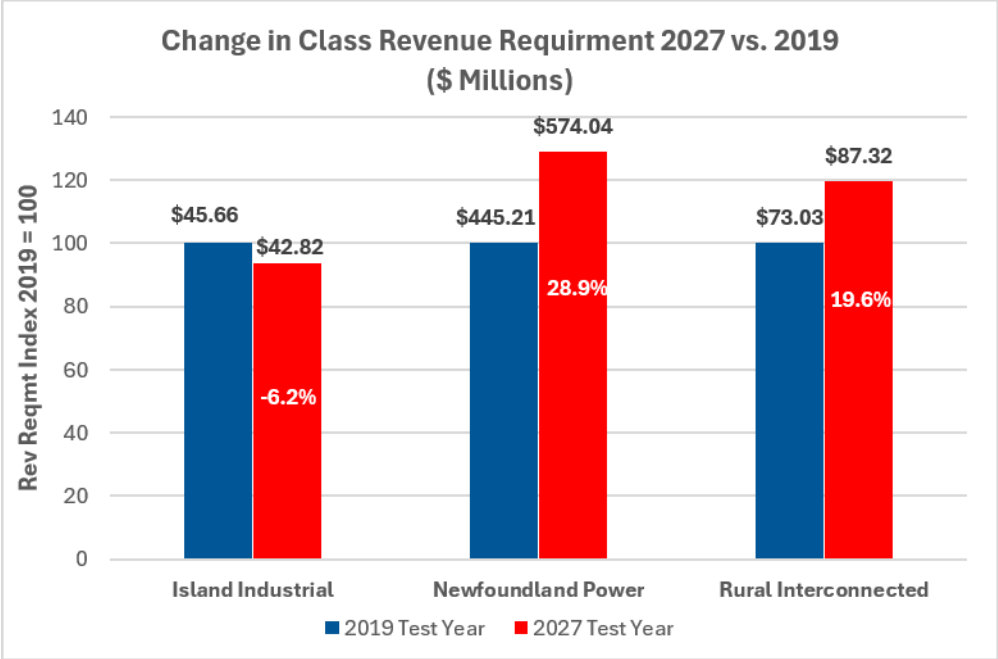
Figure 2:

Changes in Class Allocated Revenue Requirement 2027 vs. 2019			
	Island Industrial	**Newfoundland Power**	**Rural Interconnected**
	($Millions)	($Millions)	($Millions)
2019 Test Year Rev Requirement	**45.66**	**445.21**	**73.03**
Change in costs (excl. direct Muskrat Falls)	(17.86)	(61.98)	0.22
Muskrat Falls supply costs	49.28	626.39	46.17
Rate mitigation	(34.27)	(435.59)	(32.11)
2027 Test Year Rev Requirement	**42.82**	**574.04**	**87.32**
Change (%) 2027 vs. 2019	**-6.2%**	**28.9%**	**19.6%**

Figure 3:

[6] 2027 COS Schedule 4; RFI IIC-011, Attachment 4

[7] RFI NP-NLH-120



The key observation flowing from these Figures 2 and 3 are as follows:

i. Despite the 102% increase in revenue requirement relative to 2019 (from $643.0 million to $1,299.7 million), which is offset by $502.0 million in Rate Mitigation as directed by the Provincial Government, the Island Industrial class's allocated costs have actually declined over the 8-year period between 2019 and 2027;

ii. Industrial's allocated revenue requirement decreases by approximately $2.85 million, or 6.2%, notwithstanding the addition of $49.28 million in Muskrat Falls supply costs. In contrast, Newfoundland Power's allocated revenue requirement increases by approximately $128.83 million, or 28.9%; and

iii. For Industrial customers, the $49.28 million of Muskrat Falls costs is offset by $34.27 million in rate mitigation, leaving a net addition of approximately $15.01 million. This is more than offset by the $17.86 million reduction in other allocated costs.

To further understand the factors contributing to the $17.86 million reduction in Island Industrial's allocated costs, excluding direct Muskrat Falls Project costs, NLH provided a reconciliation in response to Request for Information ("RFI") CA-NLH-276. The reconciliation distinguishes the effects of changes in underlying supply costs from changes in classification and customer allocation factors, as illustrated in the following figure:

Figure 4:

Table 1: Main Contributors to Island Industrial Customers Cost Change ($ Millions)[1]

Description	2019TY	2027TY	Variance
Holyrood Fuels	20.69	5.62	(15.06)
Power Purchases – Off-Island	1.52	-	(1.52)
Power Purchases – Other	5.44	3.98	(1.46)
Total of Identified Items	**27.64**	**9.60**	**(18.04)**
Other Cost Changes, Net			0.19
Total Cost Change			**(17.86)**

Figure 5:

Table 2: Reconciliation of Island Industrial Change in Costs ($ Millions)[2]

Description	Revenue Requirement	Incremental Change	Cumulative Change from 2019TY
2019 Test Year Baseline	45.662		
Substitute 2027 Costs Amounts[3]	30.137	(15.525)	(15.525)
Substitute 2027 System Load Factor	30.068	(0.069)	(15.593)
Substitute 2027 Wind Capacity Factor	29.752	(0.316)	(15.910)
Substitute 2027 Customer Allocators	27.619	(2.133)	(18.043)
Other Differences (Residual)	27.804	0.185	(17.858)
2027 Test Year	**27.804**		**(17.858)**

The key observations flowing from these Figures 4 and 5 are as follows:

i. Approximately $15.910 million of the $17.86 million Island Industrial class's overall reduction is attributable to lower allocated power purchase costs (associated with Holyrood, Off Island and Other Power Purchases) and associated classification changes;

ii. Changes in Island Industrial's customer allocation factors account for a further reduction of approximately $2.133 million, partially offset by $0.185 million in other differences representing approximately 1% of the total reduction; and

iii. Accordingly, the reduction in Industrial's allocated costs excluding Muskrat Falls is predominantly explained by lower allocated supply expenditures, primarily related to Holyrood fuel costs.

4.3 The Classification of Muskrat Falls Costs Has Profound Implications for Interclass Cost Allocation flowing from the 2027 COS Study

The classification of Muskrat Falls costs between demand and energy has significant implications for the allocation of costs among Hydro's customer classes flowing from the

2027 COS Study. This arises from differences in the demand and energy requirements of customer classes and, consequently, the allocation factors used in the COS Study.

For the 2027 Test Year, Island Industrial customers are allocated approximately 4.98% of demand-related costs and 8.65% of energy-related costs. Newfoundland Power, by comparison, is allocated approximately 88.74% of demand-related costs and 84.84% of energy-related costs.

Accordingly, a methodology that assigns a greater proportion of Muskrat Falls costs to demand results in a lower allocation of those costs to Island Industrial customers and a higher allocation to Newfoundland Power than a methodology that assigns a greater proportion to energy.

Under the approved SLF methodology, 49.71% of Muskrat Falls costs are classified as demand-related and 50.29% as energy-related. Applying the respective class allocation factors results in approximately 6.83% of these costs being allocated to Island Industrial customers and 86.78% to Newfoundland Power.

The financial significance of this classification decision is illustrated using NLH's 2027 Test Year Muskrat Falls costs in the following Figure:

Figure 6[8]:

SLF Classification - Muskrat Falls - 2027 Test Year	
Cost Component	**$ Millions**
Muskrat Falls Power Purchases	$269.14
Labrador Transmission Assets	$46.15
Labrador-Island Link	$465.08
Total	**$780.36**

To illustrate the significance of the classification methodology, I have calculated the effect of classifying these costs entirely as energy-related, rather than applying the approved SLF methodology. This calculation holds the 2027 Test Year class allocation factors constant and changes only the demand/energy classification of the identified costs.

The purpose of this calculation is not intended to recommend that Muskrat Falls costs be classified entirely as energy-related. Rather, it provides a benchmark against which to assess the financial consequences of the approved classification methodology.

Figure 7[9]:

[8] 2027 COS Study, Schedule 4.4; RFI IIC-NLH-011, Attachment 4.

[9] Calculated using Hydro's 2027 SLF of 50.29%, 2027 demand and energy allocation factors reported in NP-NLH-120, and Muskrat Falls costs identified in the 2027 COS Study. Figures are approximate.

Illustrative Effect of Alternative Muskrat Falls Classification — 2027 Test Year		
	Island Industrial	**NP**
Demand Allocation factor	4.98%	88.74%
Energy Allocation factor	8.65%	84.84%
Blended Allocation Factor - Approved SLF	6.83%	86.78%
100% Energy Classification	8.65%	84.84%
Change in gross allocated Muskrat Falls costs ($ Millions)	**$14.24**	**($15.13)**
	Island Industrial	**NP**
	($Millions)	($Millions)
2027 Allocated Revenue Requirement	$42.82	$574.04
Change Under 100% Energy Classification	$14.24	($15.13)
Change as a % of 2027 Allocated Rev Requirement	**33.3%**	**-2.6%**

The key observations flowing from this Figure are as follows:

i. Classifying Muskrat Falls costs entirely as energy-related would increase the costs allocated to Island Industrial customers by approximately $14.2 million annually and reduce those allocated to Newfoundland Power by approximately $15.1 million, compared with the approved SLF methodology as reflected in the 2027 COS Study;
ii. The impact is equivalent to approximately 33.3% for Island Industrial and 2.6% for Newfoundland Power, of their 2027 allocated revenue requirements; and
iii. While these percentages compare changes in gross allocated costs with revenue requirements after rate mitigation and therefore do not represent the net financial impacts of an alternative classification methodology, they are illustrative of the significance of the classification decision consequence.

It is noted that the foregoing analysis illustrates the gross cost allocation consequences of an alternative classification methodology. It does not reflect corresponding changes in the classification and allocation of rate mitigation funding, net export revenues and other applicable credits. Accordingly, the calculated differences should not be interpreted as the net changes in class cost responsibilities that would result from adopting an alternative methodology.

Although the illustrative analysis does not represent the net changes in class cost responsibilities that would result from adopting an alternative methodology, it demonstrates that the classification of Muskrat Falls costs between demand and energy has fundamental implications for the distribution of costs among customer classes.

In my view, this is an important consideration in evaluating the 2027 COS Study. The approved SLF methodology is an established and administratively straightforward approach

to classifying generation costs. However, the resulting allocation is not a precise measurement of the economic responsibility of individual customer classes for the Muskrat Falls investment.

Given the magnitude and enduring nature of the Muskrat Falls costs, it is important that the implications of alternative classification methodologies be understood when interpreting the resulting class cost responsibilities. This does not establish that the approved SLF methodology is inappropriate, but it does demonstrate that a methodological choice with fundamental impacts on class cost responsibility warrants careful consideration.

Because Muskrat Falls is a long-lived investment that could be anywhere from 60 years up to 100 years, or certainly decades, the allocation consequences of the selected COS methodology will persist far beyond the 2027 Test Year.

4.4 Evaluation of NLH's Cost of Service Sensitivity Analyses

In response to information requests, NLH provided sensitivity analyses examining the effects of selected alternative COS assumptions on class cost allocations. These included changes to the system load factor (SLF) used to classify Muskrat Falls costs, the classification of wind purchases and Holyrood fuel costs, and the generation credit assigned to Newfoundland Power.

In response to PUB-NLH-104, NLH examined the effects of increasing and decreasing the 2027 SLF by two percentage points from the filed value of 50.29%, to 52.29% and 48.29%, respectively. The resulting changes in class allocated costs are illustrated in the figure that follows.

NLH also consolidated several individual sensitivity results for Island Industrial customers in CA-NLH-286, Attachment 1. Holding Industrial revenues constant, the alternative SLF assumptions produced RCCs of approximately 0.994 and 1.006, compared with 1.000 in the filed Study. The alternative wind-purchase classification and Newfoundland Power generation-credit sensitivities produced RCCs of approximately 0.997 and 0.994, respectively. The alternative Holyrood fuel classification produced a more substantial result, increasing the Industrial RCC to approximately 1.059.

Figure 8: Changes Relative to the 2027 COS Study

NLH's 2027 SLF Sensitivity Analysis		
Customer Class	**52.29% SLF**	**48.29% SLF**
	($Million)	($Million)
Newfoundland Power	(0.283)	0.283
Island Industrial	0.266	(0.266)
Rural Interconnected	0.017	(0.017)

The key observations that flow from this series of analysis are as follows:

i. The results demonstrate that the class cost allocations are sensitive to the particular methodological assumptions being tested, although the magnitude of the effect varies considerably; and
ii. The sensitivity in PUB-NLH-104 examines relatively small changes in the SLF around the 2027 value. It therefore provides useful information concerning the effect of changes in the numerical value of the SLF but does not examine the consequences of applying a materially different methodology to classify Muskrat Falls costs between demand and energy.

In my view, however, the SLF sensitivities provided by NLH should be interpreted in light of their limited scope. This distinction is important. A relatively small change in the SLF produces a correspondingly limited change in class allocations. It does not necessarily follow that the choice between SLF and other recognized generation-classification methodologies would have similarly limited consequences.

The illustrative sensitivity in Section 4.3 above addresses a different question and is not directly comparable to NLH's COS sensitivities. In particular, NLH's reported sensitivities reflect the specified treatment of offsetting amounts, whereas the illustration in Section 4.3 isolates gross Muskrat Falls costs.

The illustrative analysis in Section 4.3 above demonstrates that materially different demand/energy classification assumptions produce substantially larger differences in the allocation of Muskrat Falls costs. Although that analysis does not represent a complete alternative COS Study, it illustrates the significance of the broader methodological question that is not addressed by varying the SLF by two percentage points in the analysis provided in response to RFI PUB-NLH-104 and CA-NLH-286.

There are also limitations associated with interpreting individual sensitivity results in isolation. The 2027 COS Study incorporates substantial rate mitigation funding and other offsets, some of which are classified and allocated using the same SLF methodology as the underlying Muskrat Falls costs. In PUB-NLH-104, NLH expressly notes that rate mitigation was not recalculated in response to the alternative SLF assumptions. Consequently, the reported sensitivities isolate the effects of the specified changes but do not necessarily represent the final class cost allocations that would result from implementing an alternative methodology together with all associated adjustments.

Further, the sensitivities consolidated in CA-NLH-286 examine several distinct COS assumptions independently. They are useful for identifying the effects of particular assumptions, but do not constitute a comprehensive evaluation of alternative approaches to the classification of Hydro's generation-related costs.

I do not interpret these limitations as demonstrating that the approved SLF methodology is inappropriate. SLF is an established and administratively straightforward classification

methodology, and its continued application is consistent with the previously approved settlement.

However, given the magnitude of Muskrat Falls costs and the differing demand and energy characteristics of Hydro's customer classes, the limited sensitivity analyses should not be interpreted as establishing that alternative classification methodologies would have immaterial consequences for class cost responsibilities, clearly this is not the case.

4.5 Classification and Allocation of Export Revenues

The commissioning of Muskrat Falls and the Labrador-Island Link has also created opportunities for Hydro to realize revenues from electricity exports. These revenues are relevant to the evaluation of the 2027 COS Study because they offset costs otherwise recovered from domestic customers.

In response to PUB-NLH-037(c), NLH confirmed that a reduction in Island Interconnected System load reduces the amount of Muskrat Falls energy required to serve domestic customers and increases the energy available for export.

In response to RFI CA-NLH-338, NLH identified approximately $40.2 million in forecast export revenues reflected in the 2027 COS Study, comprising $38.1 million from exports recognized through the monetization of deferred energy and $2.1 million in net margin from incremental recapture energy. The $40.2 million in forecast export revenues reflected in the 2027 COS Study represents approximately 5.2% of the $780.4 million in annual Muskrat Falls generation and associated transmission costs and is relatively modest at this time.

Under the approved system load factor (SLF) methodology, export revenues are classified between demand and energy and allocated among customer classes on the same basis as the associated Muskrat Falls costs [10]. The application of a consistent classification methodology to Muskrat Falls costs and related export revenues provides symmetry between the allocation of costs and associated benefits. This is an important consideration and supports the internal consistency of the approved approach, at least at a time where export revenues are a relative byproduct of NLH's system.

However, the relationship between domestic customer requirements and export opportunities can be highly complex than the application of a common demand/energy classification factor.

[10] The resulting offsetting credits are approximately $34.9 million for Newfoundland Power, $2.7 million for Island Industrial customers and $2.6 million for Island Rural Interconnected customers.

Customer classes have different load characteristics, including differences in their demand and energy requirements and the timing of those requirements. Capacity required to meet domestic peak demand may be available to support exports during periods of lower domestic demand, while customers with relatively consistent energy requirements may utilize a greater proportion of available capacity throughout the year.

These differences can influence the quantity and timing of energy available for export. However, the resulting export opportunities also depend on hydraulic conditions, transmission availability, contractual arrangements and market prices. Customer load characteristics alone therefore do not establish the relative export benefits attributable to individual classes.

In my view, the treatment of export revenues is relevant to a comprehensive assessment of the classification and allocation of Muskrat Falls costs. Although the application of the approved SLF methodology provides consistency between the allocation of costs and related credits, it does not necessarily establish that the resulting allocation precisely reflects the contribution of individual customer classes to export opportunities.

Given that the evidence in this proceeding does not establish that an alternative allocation of export revenues would be more appropriate, nor does it quantify the resulting class impacts and given that the total quantum of export revenues in terms of dollars effectively represent a byproduct at the current time of NLH's system, I am not recommending a change to the approved treatment in this GRA.

4.6 Wind ELCC Does Not Justify Increasing Demand Classification to 43% as Proposed

Hydro proposes to revise the classification of wind power purchase costs in its 2027 COS Study from the previously approved 22% demand and 78% energy classification to 43% demand and 57% energy. The proposed classification is based on Hydro's updated assessment of the marginal Effective Load Carrying Capability (ELCC) of wind generation, which attributes a 43% capacity contribution to an incremental 50 MW of wind generation.

The proposed change raises an important question concerning the relationship between the capacity contribution attributed to wind generation and the appropriate classification of its purchase costs. Wind is an intermittent, non-dispatchable resource whose output depends upon prevailing wind conditions. While wind generation contributes to meeting the system's energy requirements and may provide capacity benefits, its contribution to resource adequacy must be distinguished from the provision of dependable, dispatchable capacity.

In CA-NLH-148, NLH confirms that it purchases electricity from its two existing wind facilities under power purchase agreements based on the energy delivered. Hydro also acknowledges that wind provides an indirect capacity benefit related to its availability during high-load periods. However, NLH confirms that wind does not provide dispatchable capacity and

therefore does not contribute to operating reserves or contingency requirements. Hydro further indicates that the existing wind facilities are excluded from its long-term resource adequacy study because their power purchase agreements expire in 2029.

The energy-based nature of these purchase arrangements is relevant to assessing cost causation. Hydro's expenditures are directly related to the quantity of wind electricity purchased, rather than to a separately contracted quantity of dependable capacity. This can be compared with other energy-related expenditures, including natural gas purchases and Holyrood fuel costs, which are classified entirely as energy-related notwithstanding that the generating facilities using those fuels may contribute to meeting system peak demand.

The basis upon which a utility incurs an expenditure is not, by itself, determinative of its appropriate COS classification. Nevertheless, the assignment of a substantial proportion of energy-based wind purchase costs to demand requires a demonstrated relationship between those expenditures and the capacity-related benefits provided by the resource.

Hydro's proposed methodology relies on the marginal ELCC of wind generation to determine the demand-related proportion of its total wind purchase costs. ELCC is a probabilistic resource adequacy measure that estimates the contribution of a generating resource to maintaining system reliability. It does not directly measure the proportion of a resource's costs attributable to meeting demand rather than energy requirements.

Accordingly, the fact that an incremental 50 MW of wind generation is assigned a marginal ELCC of 43% does not establish that 43% of the total contractual purchase costs associated with Hydro's existing wind facilities should be classified as demand-related. The application of a marginal capacity measure to the entire purchase cost requires a separate cost-causation justification.

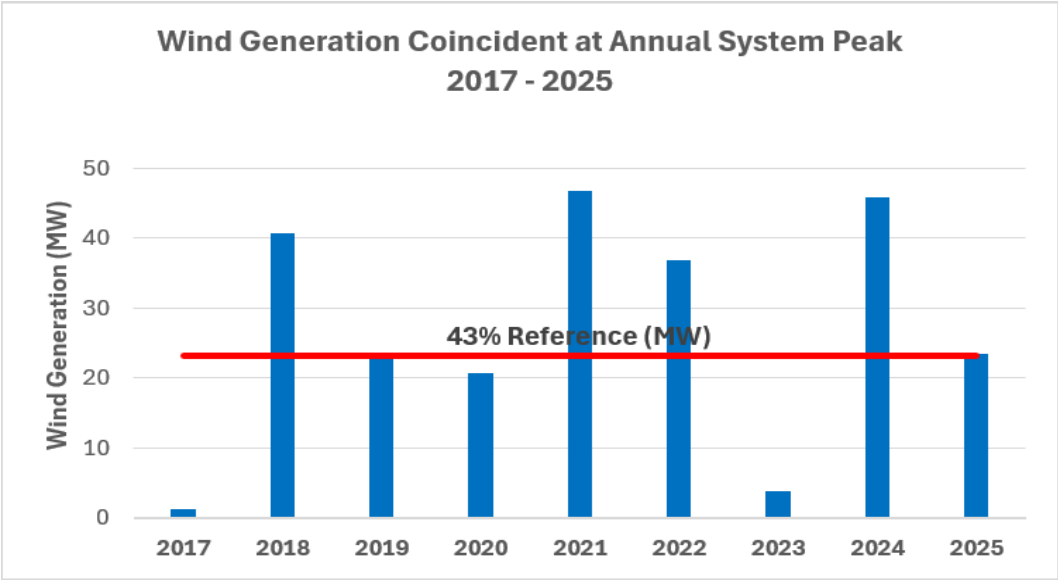
Historical Wind Generation During Peak Demand

Hydro's response to CA-NLH-150 provides historical information concerning the contribution of its existing wind facilities during periods of peak system demand. Over the 2017 to 2025 period, the combined St. Lawrence and Fermeuse wind facilities, with installed capacity of 54 MW, had an average annual capacity factor of approximately 38%. By comparison, their average output during the ten highest system load hours in each year was approximately 53% of installed capacity.

Hydro also reports that wind output exceeded 43% of installed capacity during approximately 67% of those high-load hours. These results demonstrate a positive relationship between wind generation and periods of high system demand, providing support for recognizing a capacity benefit from wind generation.

However, the historical results demonstrate considerable variability in the availability of wind generation at the annual system peak as illustrated in the Figure below: As illustrated in the Figure below,

Figure 9[11]:



.

The key observations flowing from this Figure include:

i. Output ranged from approximately 1.2 MW in 2017 and 3.7 MW in 2023 to approximately 46.8 MW in 2021 and 45.9 MW in 2024, against installed capacity of 54 MW;
ii. Wind generation was below the 23.22 MW (43%) reference in four of the nine years (2017, 2019, 2020 and 2023); and
iii. In 2017 and 2023, it was particularly low, at 1.2 MW and 3.7 MW, respectively.

This historical evidence therefore supports the conclusion that wind generation has provided a meaningful contribution during periods of high system demand at times, its contribution is clearly variable and cannot be relied upon in the same manner as dispatchable generation during a particular peak period.

These observations do not invalidate Hydro's ELCC assessment. The contribution of wind to resource adequacy is properly evaluated on a probabilistic basis, taking account of its availability during periods of system need and the reliability characteristics of the broader generation portfolio. Historical generation at individual annual peaks is not, by itself, sufficient to establish or disprove an ELCC estimate.

However, the historical evidence reinforces the importance of distinguishing between the capacity value attributed to wind for resource planning purposes and the appropriate demand-related classification of its purchase costs. Even where a marginal ELCC estimate

[11] RFI CA-NLH-150, Table 2, page 2. Combined installed capacity: 54 MW. The horizontal reference line represents 43% of installed capacity (23.2 MW), not a minimum output requirement

is technically supportable, it does not necessarily follow that the same percentage should be applied to the total cost of energy purchased under the existing wind contracts.

The treatment of wind generation in other jurisdictions provides a relevant basis for evaluating Hydro's proposed methodology. However, differences in contractual arrangements, resource portfolios, system reliability requirements and regulatory circumstances must be considered when assessing the applicability of those approaches.

Two highly comparable utilities to NLH, Manitoba Hydro and BC Hydro, both with significant hydraulic electric infrastructure assume a 100% energy classification [12] and 93% energy/7%[13] demand for purposes of the classification of Wind costs.

Implications for Class Cost Responsibilities

The financial implications of Hydro's proposed classification are illustrated in CA-NLH-147. Hydro forecasts approximately $15.68 million in wind purchase costs for the 2027 Test Year. Relative to the previously approved 22% demand and 78% energy classification, the proposed 43% demand and 57% energy classification increases the costs allocated to Newfoundland Power by approximately $128,500 and reduces the costs allocated to Island Industrial customers by approximately $120,900, holding other assumptions constant.

While these class impacts are relatively modest in the context of Hydro's overall 2027 COS Study, the proposed change is nevertheless significant from a methodological perspective. It would nearly double the proportion of wind purchase costs classified as demand-related and establish a treatment that could become increasingly consequential if wind generation assumes a greater role in Hydro's future supply portfolio.

Conclusions and Recommendations

In my view, Hydro has not sufficiently demonstrated that the marginal ELCC of an incremental wind resource provides an appropriate basis for classifying 43% of the total costs of its existing energy-based wind purchases as demand-related. The evidence supports recognizing a capacity contribution from wind generation, but the recognition of that contribution for resource adequacy purposes does not necessarily establish an equivalent demand-related cost responsibility for COS purposes.

Accordingly, I recommend that the Board deny Hydro's proposed change to 43% demand and 57% energy for the 2027 COS Study. Rather, the currently approved classification of 22% demand and 78% energy should be retained pending a more comprehensive assessment of the appropriate methodology. This recommendation should not be interpreted as establishing that the previous classification is necessarily the most appropriate long-term treatment, but rather that the proposed change has not been adequately justified.

[12] MPUB Order 43/26, pgs. 211, 214;
[13] 2017 Cost of Service Analysis and Rate Design Application, Exhibit B-8, BCUC IR No. 1, IR 24.1

It is further recommended that Hydro undertake a comparative assessment of alternative methodologies for classifying wind power purchase costs in advance of its next comprehensive COS Study or GRA. That assessment should consider the contractual basis of the purchases, the dependable capacity contribution attributed to the existing wind facilities, the relationship between marginal ELCC and the classification of total purchase costs, and the treatment of comparable energy-related expenditures. It should also quantify the implications of alternative methodologies for class cost responsibilities.

4.7 Holyrood's Changed Role Warrants a Classification Review

Hydro proposes to retain the existing methodology for classifying the costs of the Holyrood Thermal Generating Station (Holyrood TGS) in its 2027 COS Study. Under this methodology, non-fuel production costs are classified between demand and energy based on Holyrood's forecast annual capacity factor, while fuel costs are classified entirely to energy.

The role of Holyrood has changed materially following the commissioning of the Muskrat Falls Project and the interconnection of the Island and Labrador systems. Rather than operating primarily as a source of thermal energy, Holyrood is now maintained principally to support system reliability, including during periods of constrained supply and transmission availability. Nevertheless, Holyrood continues to form part of Hydro's generation portfolio relied upon to meet the interconnected system's capacity, energy and reliability requirements.

For the 2027 Test Year, Hydro forecasts approximately 455 GWh of Holyrood generation, of which approximately 424 GWh is associated with minimum operating commitments and the remaining 31 GWh with additional dispatch. Hydro's forecast also indicates that Units 1 and 2 will operate seasonally, while Unit 3 will remain available but is not scheduled to operate.

Under the existing capacity-factor methodology, Holyrood's forecast capacity factor of 11.16% results in a classification of 88.84% of its non-fuel production costs as demand-related and 11.16% as energy-related. This compares with a 15.74% energy classification in the 2019 Test Year. The declining capacity factor therefore results in a greater proportion of Holyrood's non-fuel production costs being classified to demand, consistent with its reduced utilization for energy production.

Hydro engaged Christensen Associates Energy Consulting (CA Energy) to assess the continued appropriateness of the capacity-factor methodology. CA Energy concluded that the existing approach provides a reasonable basis for classifying Holyrood's production plant costs. However, as confirmed in PUB-NLH-172, CA Energy was not engaged to undertake a comparative assessment of alternative classification methodologies. Hydro also did not adopt the consultant's suggestion to consider separate classification of the unit serving primarily a peaking function, citing the potential rotation of operating roles among units and complications associated with their differing depreciation treatment.

In my view, Holyrood's changed operating role raises a legitimate question regarding whether its forecast annual capacity factor continues to provide the most appropriate basis for classifying its non-fuel production costs. While the increasing demand-related classification may reasonably reflect Holyrood's continuing capacity and reliability functions, the capacity-factor methodology does not directly assess the relative contributions of those functions and its energy-producing role.

There is also a broader methodological question concerning the treatment of Holyrood within Hydro's interconnected generation portfolio. Holyrood continues to provide services that support the system's combined demand, energy and reliability requirements. This raises the question of whether a system-based methodology, such as System Load Factor (SLF), should be considered as an alternative to a classification based principally on the utilization of an individual generating station. For the 2027 Test Year, application of SLF would result in a classification of 49.71% demand and 50.29% energy, compared with 88.84% demand and 11.16% energy under the existing methodology. This illustrates the potential significance of the methodological choice, although it does not establish that SLF would more appropriately reflect Holyrood's particular functions.

At the same time, the available evidence does not establish that an alternative methodology would produce a more reasonable allocation of Holyrood's costs among customer classes. In particular, Holyrood's dispatchable capacity and reliability functions may warrant a different classification approach from resources that primarily provide energy. Accordingly, I do not recommend a change to the existing methodology for purposes of the 2027 COS Study.

It is recommended that Hydro undertake a comparative assessment of alternative methodologies for classifying Holyrood's non-fuel production costs in advance of its next comprehensive COS Study or GRA. The assessment should consider the existing capacity-factor methodology, SLF and unit-specific classification, including the treatment of units maintained primarily for standby or peaking purposes. It should also examine Holyrood's ongoing role in meeting the interconnected system's capacity, energy and reliability requirements and quantify the implications of alternative methodologies for class cost responsibilities.

Such a review would provide a stronger evidentiary basis for determining whether the existing methodology continues to appropriately reflect Holyrood's functions within Hydro's interconnected generation portfolio.

5.0 The 2027 RCCs Should Inform, Not Dictate, Interclass Rate Realignment

The detailed examination of the methodologies and assumptions underlying Hydro's 2027 Cost of Service ("COS") Study in Section 4 was undertaken to assess the reasonableness of the resulting class cost allocations and their implications for Hydro's proposed rate changes, particularly for Island customer classes.

This section builds on that examination by considering the resulting revenue-to-cost coverage ratios ("RCCs"), the relationship between allocated costs and class revenues, and the weight that should be placed on the COS results when determining appropriate class revenue responsibilities.

5.1 Interpretation of the 2027 COS Results and Class Revenue Responsibilities

Hydro's 2027 COS Study provides both unmitigated and mitigated class cost allocations and RCC results. As shown in Figure 1 in Section 3, the unmitigated RCCs for Newfoundland Power and Rural Labrador Interconnected are approximately 1.09, increasing to approximately 1.11 under the mitigated study. Island Industrial and Labrador Industrial RCCs are approximately 1.00, while the Rural Island Interconnected RCC increases from approximately 0.58 to 0.79 following mitigation.

Hydro's proposed class revenues reflect the results of the mitigated COS Study, together with the applicable treatment of the Rural Deficit and government rate policies.

The distinction between the unmitigated and mitigated results is important. The unmitigated study provides an indication of class cost responsibilities before the application of rate mitigation associated with the Muskrat Falls Project. The mitigated study reflects the cost allocations after those adjustments and provides a more direct basis for the proposed 2027 rate outcomes.

However, neither set of RCCs should be interpreted without consideration of the treatment of the Rural Deficit. Newfoundland Power's reported mitigated RCC is approximately 1.11. When its assigned Rural Deficit responsibility is recognized, its adjusted RCC is approximately 1.00. A similar adjustment reduces the reported RCC for Rural Labrador Interconnected from approximately 1.11 to 1.00.

Accordingly, the reported RCC of 1.11 does not establish that Newfoundland Power is contributing 11% more than its total assigned cost responsibility. The difference principally reflects the treatment of the Rural Deficit within the COS presentation.

The results also demonstrate that RCC unity is not applied uniformly across all customer classes. In particular, the Rural Island Interconnected and isolated classes remain below unity, reflecting applicable rate policies and other considerations.

Hydro's response to CA-NLH-117 confirms that it expressly targets RCC unity for Island and Labrador Industrial customers but does not target a particular RCC or tolerance band for classes affected by the Rural Deficit. For Newfoundland Power, forecast revenues are

approximately equal to its total assigned costs once its Rural Deficit responsibility is included.

Consequently, Hydro's proposed rates substantially implement the class revenue responsibilities determined by its 2027 COS Study, rather than incorporating a separate transition toward those results. This makes the reasonableness of the underlying cost allocations particularly consequential to the proposed rate outcomes.

It is also noteworthy that Hydro proposes to phase in rate increases for Rural Labrador Interconnected customers at an average of 2.25% annually over the 2027–2030 period, with the associated revenue deficiencies deferred for future recovery. This demonstrates that Hydro's proposed rate design does not uniformly require immediate recovery of the revenue responsibilities indicated by its COS Study and that considerations beyond achieving RCC unity are reflected in its proposals.

The comparative analysis in Section 4.2 demonstrates that the distribution of allocated costs among customer classes has changed substantially between the 2019 and 2027 Test Years. These changes reflect the combined effects of Hydro's transformed supply costs, the application of approved COS methodologies, changes in allocation factors and rate mitigation. The resulting differences in class cost responsibilities cannot be attributed to any single factor.

For rate-setting purposes, the important question is whether these resulting cost responsibilities provide a reasonable basis for the proposed class revenue requirements and rate adjustments. The reduction in Island Industrial's allocated costs does not, in itself, establish that the proposed Industrial rate decrease is either appropriate or inappropriate. Rather, it reinforces the importance of assessing the weight that should be placed on the COS results when determining relative class revenue responsibilities.

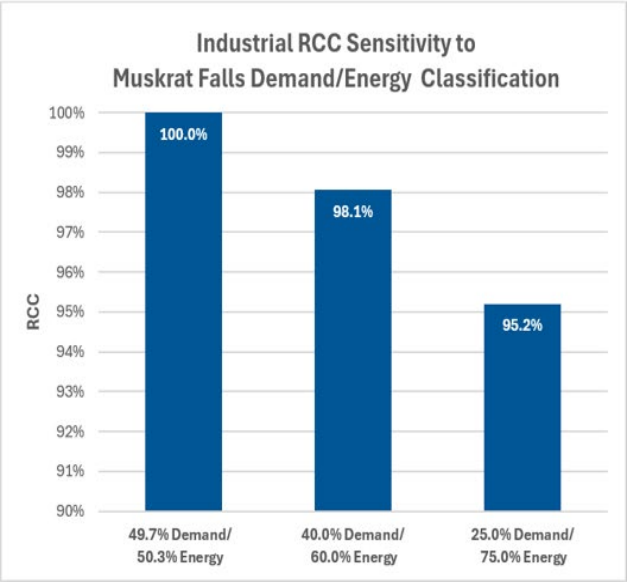
5.2 RCC Sensitivities Can Obscure Material Dollar Impacts

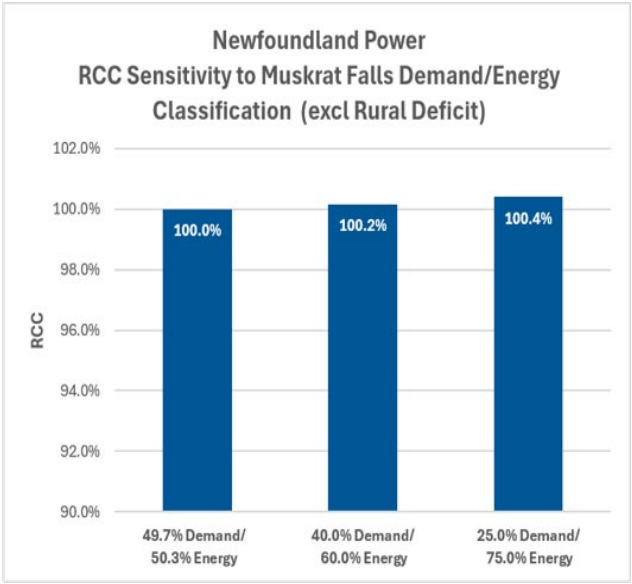
Section 4.4 examines the COS sensitivity analyses provided by Hydro in response to information requests, including the effects of alternative methodological assumptions on class cost allocations and RCCs. That examination identifies limitations in the scope of the sensitivities tested and the conclusions that can reasonably be drawn from them.

An additional consideration for interpreting RCC results is the relationship between changes in allocated costs, the size of each class's cost base and the resulting movement in its RCC.

To examine this relationship, illustrative sensitivities using alternative demand/energy classifications of Muskrat Falls-related costs are presented below. The analysis compares the filed classification of approximately 49.7% demand and 50.3% energy with alternatives of 40% demand/60% energy and 25% demand/75% energy. The calculations retain the filed class revenues and adjust the relevant net allocated costs, including the associated treatment of mitigation and export credits.

Figure 10[14]:





The key observations flowing from Figure 10 are as follows:

i. The classification of Muskrat Falls-related costs has a material impact on the Island Industrial RCC. Reducing the demand classification from approximately 49.7% to 25% decreases the Island Industrial RCC from approximately 1.00 to 0.95, holding class revenues constant;

ii. The corresponding impact on Newfoundland Power's RCC is considerably smaller. Over the same range of classification assumptions, Newfoundland Power's RCC, after recognizing its assigned Rural Deficit, increases from approximately 1.000 to 1.004; and

iii. The achievement of RCC unity is sensitive to the underlying classification assumptions. The illustrative results demonstrate that an RCC of 1.00 reflects the application of the selected COS methodology and should not, by itself, be interpreted as establishing the only reasonable allocation of class revenue responsibilities.

The substantially different movements in the RCCs do not, however, indicate correspondingly different dollar consequences. As illustrated in Figure 11, the changes in net allocated costs are of comparable magnitude but represent substantially different proportions of each class's allocated cost base.

[14] Unlike the cost allocation illustration in Section 4.3, these calculations are intended to illustrate the resulting changes in net allocated costs and RCCs. They are illustrative calculations rather than complete alternative COS model runs and should not be interpreted as the results of fully recalculated COS studies.

Figure 11: Illustrative Cost Allocation and RCC Impacts — 25% Demand Classification

Measure	Island Industrial	Newfoundland Power
Net Allocated costs	$42.82 million	$574.04 million
Change in Net Allocated costs	+$2.16 million	($2.30 million)
Change in RCC (percentage points)	−4.80	+0.40

The key observations flowing from Figure 11 are as follows:

i. Under the illustrative 25% demand classification, net allocated costs increase by approximately $2.16 million for Island Industrial customers and decrease by approximately $2.30 million for Newfoundland Power. Despite the comparable dollar impacts, the resulting RCC movements differ substantially, at approximately 4.8 percentage points for Island Industrial and 0.4 percentage points for Newfoundland Power; and

ii. The differing RCC movements reflect, in part, the substantially different allocated cost bases of the two classes. Changes in allocated costs have a greater proportional effect on the RCC of the smaller Island Industrial class than on Newfoundland Power's RCC. Consequently, an assessment focused primarily on RCC movements may understate the financial significance of changes in cost responsibility for larger customer classes, including Newfoundland Power and ultimately its residential customers.

In my experience, this is an important consideration in evaluating COS results for utilities where residential customers account for a substantial proportion of the overall allocated cost base. Relatively modest movements in residential RCCs can accompany dollar changes comparable to those producing much larger RCC movements for smaller customer classes.

The illustrative analysis demonstrates that alternative classification assumptions can change class cost responsibilities and that RCC movements alone are an incomplete measure of the financial consequences. Both the dollar and proportional impacts on all materially affected customer classes should therefore be considered when assessing interclass equity.

5.3 RCCs at Unity Is Not the Sole Measure of Interclass Equity

Hydro has indicated in CA-NLH-286 that, under normal circumstances, rates would be designed to achieve an RCC of 1.00. For Island Industrial customers, Hydro's proposed 2027 revenues correspond to an RCC of approximately 1.00, indicating that forecast revenues equal the costs allocated to the class under the selected COS methodology.

RCC unity is an important reference point in assessing the relationship between class revenues and allocated costs. It provides a useful indication of whether a customer class is contributing revenues broadly consistent with the responsibilities assigned to it under the COS Study.

However, an RCC of precisely 1.00 does not independently establish that the resulting revenue responsibility represents the only reasonable or equitable outcome.

As demonstrated in Section 4, the resulting cost allocations depend on methodological judgments that can have material consequences for individual customer classes. Accordingly, while the COS results provide an important analytical foundation for rate setting, the achievement of RCC unity should not, in itself, determine the appropriate revenue responsibility of each class.

This distinction is particularly important where the application of COS results would support materially different rate adjustments among customer classes. The Board's assessment should therefore consider not only the calculated RCCs, but also the significance of the methodological judgments underlying those results and the broader implications for interclass equity.

An additional consideration in assessing interclass equity is the extent to which customer classes bear the continuing costs and risks associated with Hydro's long-lived infrastructure.

Changes in customer loads or allocation factors may alter the distribution of embedded costs among classes even where Hydro's underlying fixed-cost obligations remain substantially unchanged. In such circumstances, the effects on Newfoundland Power and residential customers warrant particular attention.

As illustrated in Section 5.2, Newfoundland Power's large allocated cost base can make changes in its RCC appear comparatively limited even where the associated dollar consequences are meaningful. This is particularly relevant where changes in class loads or allocation factors alter the distribution of costs among classes over time.

The potential for changes in class cost responsibilities to be obscured by relatively small RCC movements reinforces the importance of considering the distribution of long-term costs and risks when assessing interclass equity.

In my view, class equity should not be assessed solely by reference to whether each class's revenues precisely equal its allocated costs in a single test year. Consideration should also be given to the durability of the underlying cost responsibilities, the effects of changing loads and the potential consequences for other customer classes.

5.4 A Range of Reasonableness is a Rate Design Tool Used to Assess the Results of a COS Study Used Almost Universally in Canadian Utility Ratemaking

The determination of a utility's rates may be viewed in three phases. The first phase focuses on the determination of the overall revenue requirement, or the overall rate level of the utility. In this phase, consideration is given to the reasonableness of the forecast of customer energy, peak load, the utility's operating and capital costs. The focus is on whether the overall utility costs and forecasts are reasonable, necessary and prudently incurred in the provision of utility service. These matters are addressed in the evidence of Mr. Rainkie.

In the second phase, the utility's established revenue requirement is allocated among its customer classes through the preparation of a cost-of-service ("COS") study. A COS study examines the costs incurred to provide service to different customers or groups of customers. Significant judgment is required throughout the study, including in the functionalization of costs, their classification between capacity, energy and customer components, and the selection of appropriate methods to allocate those costs among classes. Examples of these judgments and other relevant considerations include:

i. Generation costs may be classified predominantly as capacity-related, notwithstanding that the utilization of generating facilities and the volume of electricity produced may also influence operating costs, maintenance requirements and asset life;
ii. Different classes of customers impose different levels of risk on the utility, including differences in load stability, demand patterns and the potential for significant changes in electricity consumption, but quantifying the appropriate cost differential is not generally attempted in a cost-of-service study;
iii. Depreciation can be vulnerable to considerations other than the physical life of generating, transmission and distribution assets; and
iv. Class energy requirements and peak demand can vary significantly from year to year, particularly for large industrial customers whose electricity consumption may be influenced by changing production levels and economic conditions.

In rate design, the third phase of ratemaking, the translation of cost-to-serve by class as determined through a cost allocation study is evaluated. In this phase, the specific design of rates (rate forms) of the various customer classes are also determined either directionally or explicitly from the output of the cost allocation study.

Rather than attempting to prepare numerous COS studies using different reasonable methodologies, a Range of Reasonableness ("ZOR") provides a practical means of recognizing the uncertainty inherent in cost allocation. A COS study cannot identify with precision the cost of providing service to each customer class, particularly where substantial joint and common costs must be classified and allocated among customers who share the use of the utility's infrastructure. Consequently, the results of a COS study represent estimates of class cost responsibilities based on the methodologies and assumptions employed, rather than uniquely correct values. This means there is no true cost allocation result but a range of values that could be considered the true value. In this case, cost

allocation and its resultant RCCs is a tool used when evaluating and setting rates for various customer classes and the degree to which revenue should move from the average increase.

As such, cost allocation and its resultant RCC ratios is a tool used when evaluating and setting rates for various customer classes. It is an indicator of the appropriate rate level, not the dictator of the required revenue. The translation of cost-to-serve to pricing should reasonably balance a utility's ratemaking objectives. Rate equity is not achieved by using the results of a cost-of-service study to set rates purely in a mechanistic manner. The results of cost-of-service studies should be seen as a tool to be used in the setting of fair, just and reasonable rates. They are not, in and of themselves, fair, just and reasonable.

A ZOR provides a means of recognizing that COS allocations are not necessarily precise measures of the appropriate revenue responsibility of individual customer classes. In my experience, in addition to uncertainty in class cost of service, factors such as regulatory policy, risk, rate shock, gradualism, historical relationships, and public policy considerations are also considered in a Range of Reasonableness in the setting of rates.

A ZOR provides a framework for exercising regulatory judgment in this process. Its rationale is not that every RCC within a specified range necessarily represents an equitable outcome. Rather, it recognizes that an RCC of precisely 1.00 should not automatically be regarded as materially more appropriate than a nearby RCC solely because it corresponds to the results of a particular COS methodology.

The analysis in Section 5.2 provides a practical illustration of this concern. Alternative classifications of Muskrat Falls-related costs produce significantly different Industrial RCC results while retaining the same class revenues. The selected classification therefore influences whether the Industrial class appears to be at, above or below RCC unity.

Further, as part of a COS methodology review undertaken by Manitoba Hydro in 2013 which was assisted by CA Energy, CA Energy stated:

"The Company's COS study results are the primary vehicle for determining the overall cost responsibility and price level for the customer classes, within both gas and electricity services. In the case of Centra's services, the class level prices to cover all non-commodity costs are set equal to the cost allocation results. Essentially, all RCC ratios are set equal to. For MH's electricity services, the revenues and prices are intended to be set at levels that would, over time, bring all classes' RCC ratios within the range of 0.95 to 1.05. The acceptance of departures of observed RCC ratios from unity, for specific customer classes, and also customer groups and market segments, suggests two things. First, that fully distributed costing (cost attribution methods) cannot identify, for sure, the true cost to provide services, in view of common costs. Second, that fairness and other criteria also weigh into the problem of determining fair and equitable utility rates.... In summary, we generally concur with the Company's current approach: targeted RCC ratios as the primary guideline to set overall price levels for customer classes, given the estimates of cost

attribution obtained from COS studies. Moreover, we suggest that the COS methodology of Centra accommodate a range of acceptable RCC ratios, in a manner similar to that of MH's approach for electricity services."[15]

The use of a ZOR is well established in Canadian utility ratemaking, although the numerical ranges adopted and the extent to which they influence actual rate outcomes vary among jurisdictions. Figure 12 summarizes Canadian electric and natural gas utility practices.

Figure 12[16]:

Utility	Range of Reasonableness
AltaGas	95%-105%
Atco	95%-105%
FEI - BC	95%-105%
Sask Energy	95%-105%
Enbridge	Closer to Unity (i.e. smaller than 95%-105%)
Centra	Unity
MH	95% - 105%
BC Hydro	95% - 105% (however, in practice, much broader)
Nova Scotia Power	95% - 105%
Hydro One	move to 90% - 110% over 3 years (2015)
NFLD Power	90% - 110%

[15] Centra 2021 COS Review, Centra Exhibit 3-0, PUB MFR 8, Attachment 1, pg. 34 of 39

[16]

AUC Decision 2014-139 (May 23, 2014), pg. 17

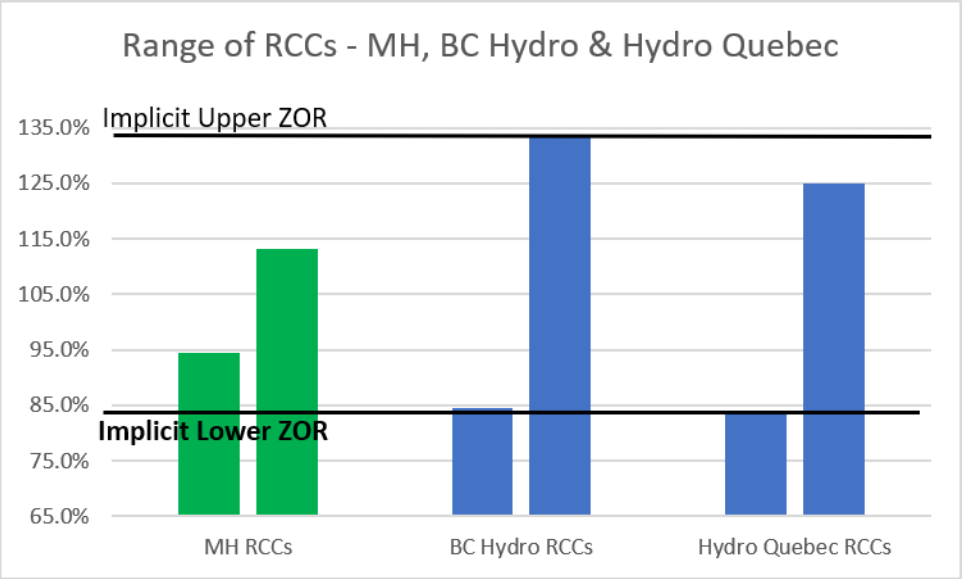
EUB Decision 2006-062 (June 27, 2006), pg. 3

SaskEnergy Rate Application - 2016, slide 19

BCUC Order G-4-18, pg. 38

OEB Order EB-2012-0459, pg. 6

Figure 13:



The key observations that flow from this figure are:

i. The vast majority of electric and natural gas utilities in Canada employ a ZOR;
ii. The use of a zone of reasonableness is not unfamiliar to the Newfoundland and Labrador Board of Commissioners of Public Utilities. In Order P.U. 13(2013), the Board accepted Newfoundland Power's proposal to vary rate increases among customer classes to achieve revenue-to-cost ratios within a target range of 90% to 110%. This provides a relevant provincial regulatory precedent for recognizing a range around RCC unity rather than requiring each customer class to achieve a ratio of precisely 1.00;
iii. Hydro-Québec is an interesting jurisdictional comparison. While it does not have a conventional Range of Reasonableness, it does have a longstanding system of interclass cross-subsidization, under which residential customers pay less than their allocated cost of service, while commercial and industrial customers contribute more; and
iv. Manitoba Hydro and BC Hydro employ a ZOR of 95% to 105%. However, actual class RCCs have, at various times, remained outside those ranges for very long periods of time. This illustrates the distinction between a target range and the application of regulatory judgment in determining the timing and extent of movements toward that range. More recently, the Manitoba Public Utilities Board has directed modest movements of class RCCs toward the established ZOR.

In my view and experience, NLH's circumstances provide a compelling basis for considering a ZOR, particularly given the substantial investment in hydraulic generation infrastructure and the significant joint and common costs that must be allocated among customer classes. The classification and allocation of these costs necessarily involve methodological judgments that can materially influence the resulting class revenue responsibilities. Given

the magnitude and long-lived nature of these investments, relatively modest differences in allocation assumptions can have significant financial consequences for individual customer classes. In these circumstances, it is difficult to conclude that the RCCs produced by any single COS methodology represent the only reasonable basis for establishing class rates.

A further consideration is the potential variability of export revenues and their effect on class RCCs. In my experience with Manitoba Hydro over several decades, changes in export revenues have materially influenced the RCCs of individual customer classes. For example, during periods of significant export revenues, Manitoba Hydro's largest General Service Large class had an RCC approaching 115%, although those export revenue levels were not expected to be sustainable over the longer term. This experience illustrates why substantial interclass rate adjustments should not necessarily follow from RCC results that may be influenced by temporary circumstances.

Taken together, these considerations support the application of a ZOR that accommodates methodological uncertainty and other relevant ratemaking considerations. While a range broader than 95%–105%, such as 90%–110%, may warrant consideration for NLH, the determination of a specific range would require further assessment of its COS methodologies, the treatment of the Rural Deficit, rate mitigation and the circumstances of individual customer classes.

Conclusions and Recommendations

NLH's 2027 COS Study provides an important analytical foundation for determining class revenue responsibilities. However, the resulting RCCs are dependent on the methodologies and assumptions used to allocate costs among customer classes. Accordingly, the achievement of RCC unity should not, in itself, determine the appropriate interclass rate outcomes.

The analysis demonstrates that alternative classification assumptions can materially affect class cost responsibilities and that the resulting RCC movements do not necessarily convey the financial significance of those changes. In particular, comparable dollar changes in allocated costs can produce substantially different RCC movements for Newfoundland Power and Island Industrial customers because of the significant differences in their respective allocated cost bases. An assessment focused primarily on RCC movements may therefore understate the consequences of methodological choices for larger customer classes.

The use of a ZOR recognizes that a COS study cannot determine with precision the appropriate revenue responsibility of each customer class, particularly given the significant joint and common costs of an electric utility and the judgments inherent in their classification and allocation. The jurisdictional experience discussed in Section 5.4 demonstrates that regulatory authorities have recognized the appropriateness of allowing departures from RCC unity when establishing fair and equitable class rates.

In my view, the Board should recognize the appropriateness of a reasonable range around RCC unity when evaluating class revenue responsibilities, rather than treating an RCC of precisely 1.00 as the required outcome. This would allow appropriate consideration of methodological uncertainty, rate stability, gradualism and other relevant ratemaking objectives.

It is therefore recommended that:

i. Recognize RCC unity as an important benchmark for evaluating class revenue responsibilities, but not as the sole determinant of fair, equitable and reasonable interclass rate outcomes;
ii. Recognize the appropriateness of applying a ZOR when assessing the RCC results of Hydro's COS Study, while acknowledging that the present evidence does not establish a specific numerical range for Hydro;
iii. Consider both the dollar and proportional consequences of alternative COS methodologies and allocation assumptions for all materially affected customer classes, rather than relying principally on changes in RCCs; and
iv. Consider the implications of changing class loads, Hydro's long-lived infrastructure costs and the potential redistribution of cost responsibilities among customer classes when assessing interclass equity.

These considerations are particularly relevant to the Board's assessment of Hydro's proposed 2027 class rate changes, including the proposed reduction for Island Industrial customers. The application of these principles to Hydro's specific rate proposals is addressed in Section 7.

6.0 Hydro's Rate Design and Mitigation Proposals Demonstrate the Limits of COS Results in Determining Rates

The establishment of rates involves more than translating the results of a cost of service (COS) study into class rates. While the COS Study provides an important basis for determining class revenue responsibilities, rate design also requires consideration of the economic characteristics of utility costs, the price signals provided to customers and the practical implications of recovering those costs through different rate structures.

These considerations are particularly relevant to Hydro's 2026 GRA, given the significant changes in its generation and supply arrangements following the integration of Muskrat Falls and the resulting changes in the classification and allocation of costs. They are also relevant to the interpretation of Hydro's proposed class revenue responsibilities, which reflect substantial government rate mitigation in addition to the underlying COS methodology.

6.1 NLH's Proposed Rate Structures Balance Embedded Cost Recovery and Marginal Price Signals

NLH is proposing several changes to the demand and energy rate structure applicable to Newfoundland Power for the 2027 Test Year:

- To increase the monthly demand rate from $5.00/kW to $5.50/kW, which it considers sufficient to maintain an appropriate demand-management signal; and
- To increase the first-block energy rate from 8.515 cents/kWh to 11.815 cents/kWh and revising the quarterly first-block energy thresholds to achieve a more consistent distribution of wholesale revenue recovery throughout the year. The proposed second-block energy rates would continue to be based on forecast seasonal export prices.

Under this approach, NLH would continue to recover a portion of its embedded demand-related costs through energy charges while using the second-block energy rates to provide price signals reflecting the opportunity cost of incremental energy consumption[17].

Additionally, NLH is proposing substantial changes to the rate structure applicable to Island Industrial customers as follows:

- To decrease the demand rate from $10.73/kW to $5.50/kW, aligning it with the proposed NP demand rate; and
- To introduce a 300-hours-of-use energy block structure, with a proposed first-block energy rate of 6.694 cents/kWh.

NLH’s proposal flows from the analysis of CA Energy, which supports a structure under which most Industrial customers would reach the second energy block in most months,

[17] Hydro, 2026 GRA, Volume I, Chapter 6, Section 6.6

thereby exposing incremental consumption to prices based on forecast seasonal export prices.

NLH states that an hours-of-use rate structure permits demand-related costs to be recovered through first-block energy rates rather than exclusively through demand charges. The proposed structure therefore retains a demand charge while recovering a substantial portion of embedded costs through first-block energy rates and providing marginal energy price signals through the second block[18].

Hydro's proposed rate structures distinguish between the recovery of embedded costs and the provision of economic price signals for incremental consumption. In both cases, Hydro proposes to recover a significant portion of demand-classified costs through first-block energy rates rather than demand charges, while using second-block energy rates to reflect forecast seasonal export prices.

This approach recognizes that rate design need not replicate the classification of costs within the COS Study. Cost classification and rate design serve different objectives, and costs classified as demand-related need not be recovered exclusively through demand charges.

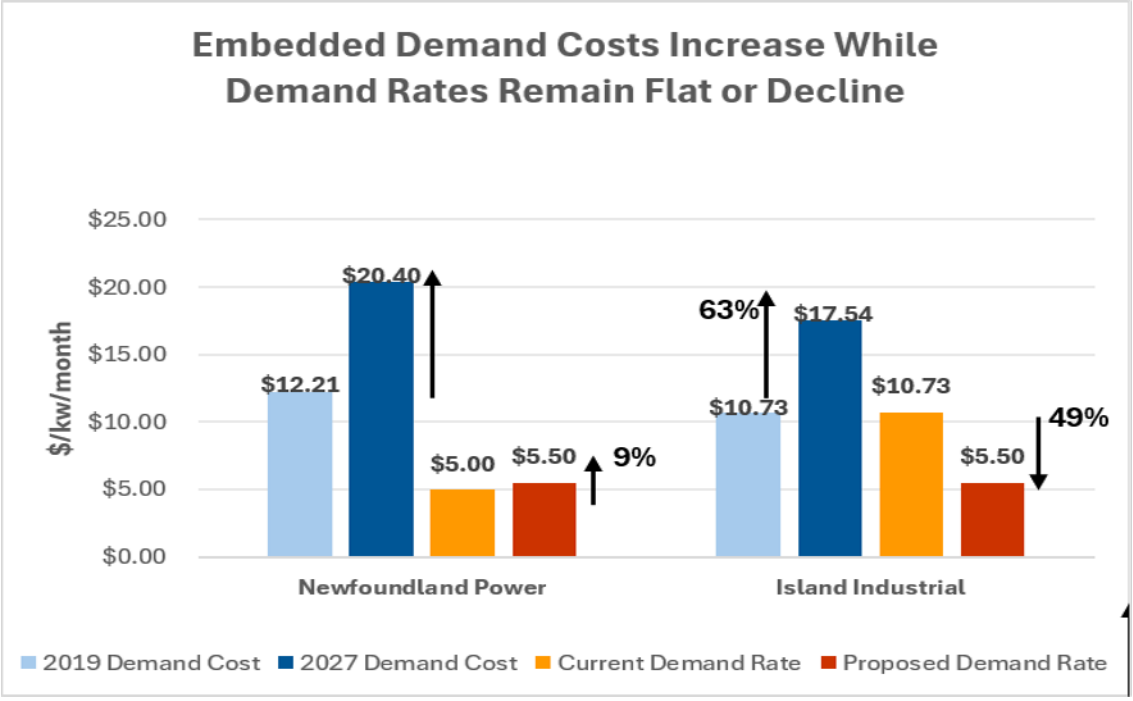
However, the extent to which Hydro proposes to recover demand-classified costs through energy rates warrants closer examination of the relationship between the economic characteristics of its generation and supply costs, their classification within the COS Study and their recovery through rates.

6.2 The Divergence Between Embedded Demand Costs and Demand Rates Raises Questions of Economic Consistency

NLH's 2027 COS Study reflects substantial increases in embedded demand-related costs relative to the 2019 COS Study. However, these increases are not reflected proportionately in Hydro's proposed demand rates as illustrated in the following Figure:

[18] Hydro, 2026 GRA, Volume I, Chapter 6, Sections 6.7.1–6.7.3, Table 6-7; CA Energy, Pricing for a Revised Island Industrial Rate for Newfoundland and Labrador Hydro, May 11, 2026, Exhibit 17.

Figure 14[19]:



The key observations flowing from the above figure are as follows:

i. **Newfoundland Power:** Embedded demand costs increase from $12.21/kW/month in the 2019 COS Study to $20.40/kW/month in the 2027 COS Study, an increase of approximately 67%. In contrast, Hydro proposes increasing the demand rate from $5.00/kW/month to $5.50/kW/month, an increase of 10%;

ii. **Island Industrial:** Embedded demand costs increase from $10.73/kW/month to $17.54/kW/month, an increase of approximately 63%. Despite this increase, Hydro proposes reducing the demand rate from $10.73/kW/month to $5.50/kW/month, a decrease of approximately 49%; and

iii. **Recovery of demand-related costs:** Hydro indicates that the proposed demand rates would recover approximately 27% of Newfoundland Power's and 31% of Island Industrial customers' embedded demand costs, with the remainder recovered through first-block energy rates.

In response to CA-NLH-163, Hydro confirmed that marginal capacity costs were not considered in establishing the proposed $5.50/kW/month demand rate for Newfoundland Power. Rather, Hydro selected a 10% increase as a modest adjustment to the existing demand charge, while maintaining the recovery of a substantial portion of demand-related costs through the first-block energy rate.

[19] Hydro, 2026 GRA, Volume I, Chapter 6, Sections 6.6–6.7; RFI CA-NLH-162(b); CA-NLH-163(b) and (d).

Hydro quantified the resulting recovery at $92.730 million through demand charges, representing approximately 27% of Newfoundland Power's $344.019 million in allocated demand-related costs before deficit and revenue credit allocation, with the remaining $251.289 million recovered through first-block energy rates.

The divergence between embedded demand costs and proposed demand rates is particularly noteworthy given the fundamental changes in Hydro's generation and supply arrangements following the integration of Muskrat Falls.

Hydro's proposals raise an important question in this regard. Given the substantial proportion of demand-classified costs recovered through energy rates, it is reasonable to examine whether the economic considerations underlying Hydro's rate design proposals also have greater relevance to the classification and allocation of generation and supply costs among customer classes.

Recovering embedded demand-related costs through first-block energy rates does not necessarily establish that those costs are caused by energy consumption. Nevertheless, the substantial flexibility reflected in Hydro's proposed rate structures reinforces the importance of examining whether the economic characteristics of its changed generation and supply arrangements have been adequately considered in the demand and energy classification methodology.

While cost allocation and rate design serve different objectives and need not produce directly corresponding results, there should nevertheless be a reasonable degree of coherence between the two. Both should be informed by a consistent understanding of the underlying economic characteristics of Hydro's generation and supply costs and the factors that give rise to those costs. This is particularly important given the significant changes in Hydro's supply arrangements following the integration of Muskrat Falls.

6.3 Rate Mitigation Materially Changes Relative Class Cost Responsibilities

The proposed 2027 rates incorporate substantial government rate mitigation associated with the Muskrat Falls Project. The mitigation arrangements are intended to reduce the costs recovered from Island Interconnected customers and support the Government's objective of limiting annual Island Domestic retail rate increases attributable to NLH’s costs to 2.25% through 2030. The Government's policy framework also contemplates compatible treatment of other Island Interconnected customers.

Hydro has reflected approximately $502.0 million of mitigation in its 2027 COS Study. The mitigation is allocated among Island Interconnected customer classes using the production demand and energy allocation methodology applicable to Muskrat Falls-related costs.

The total comprises approximately $249.5 million associated with production demand and $252.4 million associated with production energy.

The figure below summarizes the allocation of mitigation credits reported in Hydro's response to PUB-NLH-105:

Figure 15:

Allocation of the 2027 Rate Mitigation Credit			
Customer Class	**Mitigation**	**Share of Mitigation**	**Credit as %**
	($M)	(%)	**of Unmitigated Costs**
NP	435.59	86.8%	43.1%
Island Industrial	34.27	6.8%	44.5%
Rural Interconnected	32.11	6.4%	26.9%
Total	**501.97**	**100%**	

The key observations flowing from Figure 13 are as follows:

i. **The magnitude of mitigation is substantial.** Approximately $502.0 million is reflected in the 2027 COS Study, of which $435.6 million (86.8%) is allocated to Newfoundland Power, $34.3 million (6.8%) to Island Industrial customers and $32.1 million (6.4%) to Rural Island Interconnected customers;

ii. **Mitigation represents different proportions of each class's unmitigated allocated costs.** The credits offset approximately 43.1% of Newfoundland Power's costs, 44.5% of Island Industrial's costs and 26.9% of Rural Island Interconnected customers' costs. Accordingly, while Newfoundland Power receives the largest mitigation credit in absolute dollars, Island Industrial customers receive a slightly greater reduction relative to their unmitigated allocated costs; and

iii. **Mitigation changes the relative distribution of allocated costs among customer classes.** Newfoundland Power's share of the combined allocated costs of the three Island Interconnected classes declines from 83.71% to 81.52%, while Island Industrial's share declines from 6.39% to 6.08%. In contrast, Rural Island Interconnected share increases from 9.90% to 12.40%, notwithstanding a reduction in its absolute allocated costs. This reflects the smaller proportional mitigation benefit received by Rural Island Interconnected customers.

The application of mitigation also affects the Rural Deficit and its recovery. In response to PUB-NLH-105, Hydro indicates that the aggregate Rural Deficit decreases from approximately $97.1 million before mitigation to $65.0 million following mitigation, a reduction of $32.1 million. Over the same comparison, Newfoundland Power's excess revenues before Rural Deficit allocation decline from approximately $95.2 million to $62.8 million, a reduction of $32.4 million. These changes are relevant to the interpretation of the RCC results discussed in Section 5, as changes in Newfoundland Power's reported RCC do not necessarily reflect corresponding changes in its dollar contribution toward Rural Deficit recovery.

The magnitude and allocation of rate mitigation are important considerations in evaluating Hydro's proposed class revenue responsibilities. The mitigated COS results reflect both the

underlying cost allocation methodology and the distribution of substantial government financial support. Accordingly, these results should not be treated as a precise or independent measure of relative class cost responsibility when evaluating Hydro's proposed class rate adjustments.

7.0 NLH's Proposed Class Rate Adjustments Warrant Reconsideration

The preceding analysis demonstrates that Hydro's 2027 Cost of Service (COS) Study reflects significant changes in its generation and supply arrangements, methodological judgments concerning the classification and allocation of costs, and approximately $502 million in government rate mitigation.

These factors are relevant not only to the interpretation of the resulting revenue-to-cost coverage ratios (RCCs), but also to the appropriate magnitude and direction of class rate adjustments.

In my opinion, the COS Study provides an important analytical foundation for determining class rates. However, its results should not be regarded as a precise or exclusive measure of the rates that are just and reasonable for individual customer classes. The determination of class rates also requires consideration of interclass equity, the differing circumstances and risks associated with customer classes, affordability, and the broader objectives of the Government's rate mitigation framework.

These considerations are particularly relevant to Hydro's proposed substantial reduction in Island Industrial rates and its intention to rely on the 2027 COS Study in establishing annual rates through 2030.

7.1 NLH's Proposed Industrial Rate Reduction Raises Interclass Equity Concerns

Hydro proposes materially different rate adjustments for Newfoundland Power and Island Industrial customers in 2027.

For Newfoundland Power, Hydro proposes a wholesale rate increase of approximately 3.3%, within the framework of the Government's policy of targeting annual Island Domestic retail rate increases attributable to Hydro's costs at 2.25% through 2030.

In contrast, Hydro proposes an overall rate reduction of approximately 14.3% for Island Industrial customers. The reduction reflects the combined effect of an increase in base rate revenues and a substantial reduction in Project Cost Recovery Rider (PCRR) revenues as shown in the figure below:

Figure 16: Island Industrial Revenue Comparison – Existing and Proposed Rates

Component	Existing ($M)	Proposed ($M)	Change ($M)
Base rate revenues	39.23	42.82	3.58
PCRR revenues	12.36	1.41	(10.95)
CDM	0.04	0.04	0.00
Total revenues	51.64	44.27	(7.37)
Overall rate adjustment			**−14.3%**

[20]

The key observations that flow from this figure are:

- **Base rate revenues increase by approximately $3.6 million**, from $39.2 million to $42.8 million, reflecting the Industrial class revenue requirement determined through the 2027 COS Study;
- **PCRR revenues decrease by approximately $10.9 million**, from $12.4 million to $1.4 million, more than offsetting the increase in base rate revenues; and
- **Total Industrial revenues decrease by approximately $7.4 million (14.3%)**, from $51.6 million to $44.3 million, resulting in a substantial overall reduction in Industrial customer bills.

In response to RFI CA-NLH-001, NLH states that the proposed Industrial rate reduction resulted from the application of its COS methodology and the Government's rate mitigation framework. NLH confirmed that it did not consider alternative cost allocation or rate design approaches to moderate the proposed Industrial rate reduction stating that such an outcome would require a different method of allocating costs in the COS Study.

The distinction between the costs allocated to a class through the COS Study and the appropriate rates to be established for that class is particularly important in the circumstances of Hydro's 2026 GRA.

The 2027 COS Study incorporates substantial government rate mitigation, which materially reduces the costs to Island Interconnected customer classes. The resulting mitigated RCCs therefore reflect both Hydro's cost allocation methodologies and the distribution of mitigation.

In response to RFI CA-NLH-312, Hydro calculated the relationship between revenues at its proposed mitigated rates and the costs allocated to each customer class before rate mitigation. The results for the three principal Island Interconnected classes are summarized in the figure below:

[20] NLH 2026 GRA, Chapter 6, Figure 6-9, pg. 6.24

Figure 17: Recovery of Unmitigated Allocated Costs at Hydro's Proposed 2027 Rates[21]

Customer class	Unmitigated Allocated Costs	Revenues at Proposed Rates	Cost Recovery	Under-Recovery		
	($M)	($M)	(%)	(%)		
Newfoundland Power	1,009.60	636.80	63.1	36.9	←	
Island Industrial	77.10	42.80	55.5	44.5	←	
Rural Island Interconnected	119.40	68.90	57.7	42.3	←	

The key observations that flow from Figure 17 are as follows:

i. All three classes recover substantially less than their unmitigated allocated costs, with recovery ranging from 55.5% to 63.1%, reflecting the significance of government rate mitigation;

ii. Island Industrial customers have the highest percentage of unrecovered costs at 44.5%, compared with 42.3% for Rural Island Interconnected and 36.9% for Newfoundland Power; and

iii. Industrial customers recover 7.6 percentage points less of their unmitigated allocated costs than Newfoundland Power and 2.2 percentage points less than Rural Island Interconnected customers, notwithstanding Hydro's proposed 14.3% Industrial rate reduction.

Importantly, the mitigated Industrial RCC of approximately 1.00 does not mean that Industrial customers are recovering their full underlying allocated costs. It indicates that Industrial revenues recover the costs assigned to the class after mitigation. Figure 17 above demonstrates the importance of distinguishing mitigated RCCs from the recovery of unmitigated costs.

The comparison raises an important question of interclass equity. NLH proposes a substantial Industrial rate reduction while Newfoundland Power faces an increase, even though Industrial customers recover a materially smaller proportion of their unmitigated allocated costs.

These results, together with the methodological judgments underlying the COS Study, provide reasonable grounds for reconsidering NLH's proposed Industrial rate adjustment. The question for the Board is not simply whether Hydro has applied its proposed COS methodology consistently, but whether the resulting class rate adjustments are just and reasonable.

[21] RFI CA-NLH-312, Table 1. Percentages calculated from Hydro's reported values. The revenues are those used in NLH's COS comparison and should not be confused with total Industrial revenues including the PCRR.

7.2 Achieving RCC Unity Should Not Determine the Appropriate Industrial Rate Adjustment

The determination of just and reasonable rates requires consideration of factors beyond the results of a COS Study. While the Study provides an important estimate of relative class cost responsibility, its results depend on the methodologies, assumptions and allocation factors employed and should not be regarded as precise measures of the appropriate rates for individual customer classes.

As discussed throughout this evidence, NLH's 2027 COS Study reflects significant changes in generation and supply arrangements, methodological judgments concerning the classification and allocation of costs, and substantial government rate mitigation. Different reasonable methodologies may produce different relative class cost responsibilities.

An additional consideration is the differing nature of the risks associated with serving residential and Industrial customers. Residential customers represent a relatively stable and enduring customer base, with limited alternatives to obtaining essential electricity service. Large Industrial customers, by contrast, may represent significant individual loads that can change materially or cease operations over the life of the utility's generation and transmission assets. The residential customer base may therefore have a continuing exposure to the financial consequences of long-lived utility investments and changes in Industrial demand.

These considerations are not proposed as additional cost allocators within the COS Study. Rather, they are relevant to the broader assessment of interclass equity and the determination of just and reasonable rates, particularly where substantial shared infrastructure costs are allocated using methodologies that necessarily involve judgment.

The Government's substantial rate mitigation framework further reinforces the importance of considering the broader rate-setting implications of NLH’s proposals. It is difficult to reconcile the underlying affordability objectives of that framework with a substantial Industrial rate reduction while residential customers continue to experience increases, without carefully considering whether the resulting distribution of costs and benefits among classes is equitable.

The issue is not whether Industrial customers should bear costs unrelated to their service, but whether NLH’s COS results provide a sufficiently definitive basis for the proposed differences in class rate adjustments.

It is recommended that the Board consider an alternative under which Island Industrial customers receive an overall rate increase of 2.25% for 2027, rather than Hydro's proposed 14.3% decrease. This recommendation reflects the relative class cost recovery illustrated in Figure 17, the methodological uncertainty inherent in the COS Study discussed extensively in this evidence, the substantial government mitigation incorporated into its results, and broader considerations of interclass equity and customer risk.

The proposed 2.25% adjustment would provide greater consistency in the overall rate adjustments experienced by Island Interconnected customer classes, having regard to the Government's 2.25% annual Island Domestic rate increase target.

Based on the approximate revenue underlying Figure 17, the alternative would produce the following results:

Figure 18: Island Industrial Revenue Implications of Alternative 2027 Rate Adjustments[22]

	NLH Proposal	Recommended Alternative
Existing Total Revenue	$51.6M	$51.6M
Overall Rate Adjustment	−14.3%	2.25%
Resulting Total Revenue	$44.3M	$52.8M
Difference from NLH Proposal	—	+$8.5M

The recommended alternative would result in approximately $8.5 million in revenues being available to reduce the amounts otherwise recovered from Newfoundland Power and Rural Island Interconnected customers under Hydro's proposal.

It is recommended that NLH be directed to propose the appropriate treatment of these revenues in establishing class rates, consistent with the applicable rate mitigation framework.

7.3 Reliance on the 2027 COS Study Through 2030 Reinforces the Need for Rate-Setting Judgment

NLH proposes to establish rates using its 2027 Test Year revenue requirement and COS Study, followed by annual rate adjustment applications through 2030 under the Government's Rate Mitigation Plan.

In response to RFI CA-NLH-224, NLH confirms that rates effective July 1, 2028, 2029 and 2030 would be established through annual rate adjustment applications rather than new General Rate Applications based on updated test years.

Hydro anticipates that the 2027 Test Year will be the only Board-reviewed test year during the remaining period of the mitigation plan. Annual rate adjustments would be driven primarily by changes to the PCRR and other applicable rate riders.

Hydro further confirms in response to RFI CA-NLH-302 that it does not anticipate updating direct COS inputs, allocation factors within the COS Study or customer class RCCs when establishing annual rates for 2028 through 2030.

[22] Calculated using rounded existing and proposed Industrial revenues. The figures are illustrative and would require reconciliation with final billing determinants and approved riders.

Hydro proposes to allocate certain supply-cost variances through rate riders using demand and energy allocation factors based on current-year values. Hydro indicates that this approach would recognize changes in customer usage when allocating applicable supply-cost variances.

Hydro is not proposing to undertake annual COS studies reflecting changes in other costs, including operating costs, depreciation and return, or the resulting changes in relative class cost responsibility.

A COS Study provides an assessment of relative class cost responsibility for a particular test year, based on forecast costs, customer loads, allocation factors and the methodologies employed. It is like a snapshot taken at one point in time. Its results are thus unlikely to be representative of the relative costs of serving individual customer classes in subsequent years, particularly recognizing that NLH sets its class cost to serve based on unity (excluding the Rural Deficit).

This distinction is particularly relevant to Hydro's 2027 COS Study, given the significant changes in its generation and supply arrangements following the integration of Muskrat Falls.

Changes in the composition of costs may affect relative class cost responsibility even where Hydro's aggregate revenue requirement remains relatively unchanged. For example, an increase in costs classified and allocated on the basis of demand, offset by a corresponding decrease in energy-classified costs, could alter the relative costs attributable to Newfoundland Power and Island Industrial customers without changing the total revenue requirement.

Hydro's proposal to use current-year demand and energy allocation factors for certain supply-cost variances would recognize some of these changes but would not provide a comprehensive reassessment of relative class cost responsibility.

Export revenues introduce a further consideration. With the Island Interconnected System connected to the North American electricity market, changes in export prices, available energy and export volumes may affect the revenues available to offset the costs of serving customers. Thus, export revenues can vary significantly from year to year.

The implications for individual classes depend not only on the magnitude of those changes but also on the treatment and allocation of export revenues within the COS Study.

While Hydro's proposed deferral and rate adjustment mechanisms would address certain variations in supply costs and related revenues, those adjustments are not equivalent to updating the overall COS Study to determine whether relative class cost responsibilities have changed.

These considerations have implications for the weight placed on achieving an RCC of precisely 1.00 when establishing 2027 class rates.

Hydro proposes to establish Industrial base rates that produce an RCC of approximately 1.00 under the mitigated 2027 COS Study. However, it does not propose to recalculate class RCCs in establishing rates for 2028 through 2030.

By not proposing to update its COS Study or recalculate class RCCs for 2028 through 2030, Hydro is effectively accepting a rate-setting framework that does not ensure RCCs remain at unity over this period as costs and loads change. This once again begs the question concerning the weight that should be placed on achieving an RCC of precisely 1.00 in establishing 2027 rates, particularly where doing so would result in a substantial reduction in Industrial rates. This further supports the exercise of judgment in determining appropriate class rate adjustments rather than treating the 2027 COS results as determinative.

In my view, a further review of Hydro's COS methodologies, focused on the classification and allocation of generation and transmission costs and the treatment of export revenues, will likely be warranted as operating experience with the interconnected system develops. While these methodologies have been reviewed previously, the potential significance of export revenues to relative class cost responsibility, together with the limited operating experience under the new supply arrangements, provides a reasonable basis for reassessing their continued appropriateness prior to or in conjunction with NLH's next GRA.

Kelly Derksen, BSc., CPA, CMA

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HANDS-ON AND MULTI-FACETED EXPERTISE

IMPROVING REGULATORY & BUSINESS OUTCOMES FOR CLIENTS

QUALIFICATIONS & EXPERTISE

- Ratemaking Expert
- Regulation Strategy & Execution
- Regulation Process Management
- Quality & Process Improvement
- Experienced & Respected Witness
- Leadership Excellence

CAREER HIGHLIGHTS

- Over 30 years of Rates & Regulation experience in the Utility Industry
- A recognized authority in Utility Cost of Service and Rate Design
- Experienced, credible, respected witness – testifying in numerous public hearings
- Developed, led, and assisted in dozens of regulatory proceedings
- Committed to mentoring and sharing knowledge through collaborative style and ongoing course instruction with the CGA

PROFESSIONAL EXPERIENCE

- Independent Consultant 2018-Present
- Manitoba Hydro/Centra Gas 1999-2017
- Centra Gas 1994-1999

EDUCATION

- Chartered Professional Accountant (CMA), 2004
- BSc., (Chemistry & Mathematics) University of Manitoba, 1995

PROFILE

Kelly leverages her 30-years of **hands-on experience** and **multi-faceted expertise** in energy regulation and ratemaking for clients that participate in and are impacted by rate-regulation – including applicants, intervenors, utility customers, regulatory & government agencies. She specializes in regulation and ratemaking, with an emphasis on cost of service, and rate design. **Clients benefit from improved regulatory & business outcomes** through the following:

Providing Clients with Ratemaking Solutions Based on Traditional and Contemporary Best Practice that are Theoretically Sound, Practical, Sustainable and Clear – Kelly developed her ratemaking expertise through decades of employment with one of Canada's largest publicly owned, vertically integrated electric and natural gas utilities as well as providing independent advice to other applicants, intervenors, and regulatory tribunals. Kelly has led, developed and executed many cost-of-service and rate design studies and methodological reviews. This includes the development of extensive evidence and providing principled persuasive testimony. Along with practical experience, and continuous monitoring of the evolving utility industry, she also has deep understanding of the academic-based writings including Bonbright and Kahn, as well as the more practical detailed ratemaking manuals such as NARUC. With a deep passion and understanding of ratemaking obtained through significant hands-on utility experience uniquely enables Kelly to deliver client solutions that are workable, understandable, and that are also academically sound.

Providing Clients with Effective Regulation Strategy Advice & Workable Process Management Solutions – Leveraging from 30 years of hands-on experience-backed judgement and insight, Kelly provides strategic and tactical advice and solutions to complex regulation challenges. Kelly has successfully developed and led many interim, ex-parte, written, traditional, and unconventional regulatory processes. With the many challenges and nuances associated with achieving success in the regulatory arena, Kelly is a champion of evaluating lessons learned to achieve future success. Clients benefit from access to decades of hands-on regulatory experience to advance their goals more efficiently and effectively.

Providing Clients with Practical and Sustainable Solutions- Kelly's collaborative style as well as her strength in the translation of complex ratemaking subject matters into workable solutions that are practical with a greater potential of stakeholder acceptance.

OVERVIEW OF RATEMAKING & REGULATORY EXPERIENCE

Over three decades of hands-on experience in developing practical solutions to complex problems that comport with best practice categorized broadly as:

1. Regulation Strategy and Process Management;
2. Ratemaking; and
3. Leadership and Communication.

Regulation Strategy and Process Management

- Provided strategic and tactical advice and solutions to Executive Management for over 15 years on ratemaking and regulatory policy consistent with the strategic goals of the organization and within the context of the governing legislation and regulatory framework.
- Led, developed, and assisted in dozens of rate cases (and other regulatory processes) interfacing with external agencies and the many internal disciplines necessary to support the process. Provided advice and reports to Executive Management regarding appropriate regulatory strategies and developed a common theme and orderly plan with careful execution to achieve strategic, financial and operational deliverables.
- Provided advice to Executive Management regarding the interpretation of regulator decisions and compliance.
- Successfully led numerous traditional, unconventional, interim and ex-parte regulatory processes. This included numerous stakeholder engagement sessions, demonstrating commitment to seeking solutions to best balance multiple conflicting interests, building trust and strengthening relationships.
- With the many challenges and nuances associated with achieving success in the regulatory arena, a champion of evaluating lessons learned for the achievement of successful future outcomes; including key stakeholders in this evaluation is critical to building solid relationships, and to move forward goals more efficiently and effectively.

Ratemaking

- A deep understanding of utility ratemaking including extensive hands-on experience having developed, led, and executed dozens of studies and several cost of service and rate design methodological reviews, through continuous monitoring of the evolving utility industry, a solid understanding of the economics behind investment decisions, the physical workings of the system, a strong understanding of the legislative framework and regulatory construct by which a utility operates, and the academic-based writings of Bonbright and Kahn as well as more practical detailed ratemaking guidance provided by NARUC.
- An experienced and respected witness having represented the Corporation as a subject matter witness before the MPUB for over two decades. Provided testimony on revenue requirements, rate base, cost of service, rate design, treatment of deferral and variance accounts, expansion financial feasibility tests, terms and conditions of service, regulatory approvals and procedural matters.
- Driving force and key witness behind the 2016 electric Cost of Service Methodology Review before the MPUB to review the methodology underpinning the allocation of a $2 billion revenue requirement, $500 million of export revenue, and a $20 billion rate base among over 570,000 customers.
- Developed the 2016 electric Cost of Service Methodology Review case strategy and evidence, hundreds of information requests, led several stakeholder engagement sessions, evaluated Intervenor Expert positions, rebuttal evidence, testimony, and final arguments available on the MPUB's website: www.pubmanitoba.ca.
- Developed evidence to support several key issues such as: an overall methodology that reasonably balanced the corporation's financial goals and the public interest given significant external energy market changes subsequent to 2008 (advent of shale gas, plunge in electric and natural gas prices) coupled with significant investment in new hydraulic

infrastructure/aging infrastructure; a cohesive overall methodology associated with a largely interconnected hydro-electric utility; the influence of economics (marginal cost to service) on embedded cost to serve; and the interrelation between revenue requirement, cost of service, and rate design and potential unintended consequences (impacts to low income customers or protecting the utility's ability to collect its approved revenue requirement).

- Recognized publicly for capabilities having developed an expert level knowledge of electric cost of service over a short timeframe to support a complex regulator review and delivering testimony.
- Led and developed numerous cost allocation and rate design models to analyze the impacts and sensitivities of scenarios.
- Conducted training on rates, cost analysis, methodology, economic feasibility (service extension), revenue requirement.
- Led and prepared the development of lead-lag studies, rate base, revenue requirements on many occasions between 1998 and 2008 for Manitoba's natural gas utility.

Leadership and Communication

- Extensively interacted with a variety of styles and experience levels having led large multi-disciplinary teams with dozens of professionals and routinely presenting to Executive Management, Board of Directors, Retail Customers, Stakeholders and the Regulator.
- Successfully advanced many regulatory applications and related hearing processes, at times concurrently, accomplished through building cross-departmental co-operation, periodically with disparate in-house teams, with a genuine interpersonal style that engenders trust and commitment. For example, over a 12-month period beginning in the fall of 2006, led and developed 4 major applications including a Cost of Gas Application, a 4-Party Trench Application; a General Rate Application; and a generic competition-related application.
- Managed and mentored a team of professional accountants. By creating a collaborative atmosphere, and encouraging measured autonomy proudly developed a well-respected flexible team with strong expertise.
- Developed productive relationships with regulator staff and advisors, key stakeholders and interest groups.
- Routinely presents at regulatory workshops and industry conferences, to strengthen skills and importantly to share knowledge and experience with others.
- Strength in translating complex ratemaking subject matter, into practical, clear solutions based on traditional and contemporary best practice and the related strategy and evidence development of a regulatory case.

PROFESSIONAL EXPERIENCE

Independent Consultant in Public Utility Regulation	**2018 - Present**
Manitoba Hydro - Manager, Cost of Service & Rates	**2009 - 2017**
Manitoba Hydro - Manager, Gas Rates & Regulatory Affairs	**2006 - 2009**
Manitoba Hydro - Senior Analyst, Gas Rates	**2002 - 2006**
Manitoba Hydro - Analyst, Gas Rates	**1999 - 2002**
Centra Gas – Revenue Requirement Analyst, Regulatory Affairs	**1998 - 1999**
Centra Gas - Coordinator, Regulatory Affairs	**1995 - 1998**

RELEVANT PROJECT EXPERIENCE:

- Provided independent expert evidence and testimony on cost allocation, rate design and load forecast matters including rate policy, range of reasonableness, the interpretation of revenue to cost ratios, the interclass impacts associated with the multibillion reduction in provincial government payment relief, the interclass impacts associated with the use of current rate base to allocate net income associated with future generation and transmission investment

not yet used and useful, the interclass impact of material reductions in export revenue associated with drought, the appropriate treatment of wind, narrowing the definition of coincident peak, and the impacts of load forecast methodology changes driving significant advancement of resource need on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2025/26 to 2027/28 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Provided independent expert evidence and testimony on cost allocation and rate design matters including the appropriateness of a range of reasonableness, the implementation of a range of reasonableness in the context of rate unbundling, class revenue to cost coverage ratios, direct assignments, design day peak, and the rate treatment of payments from government on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. 2024/25 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Provided independent expert evidence and testimony on cost allocation and rate design and terms and conditions of service matters which include: rate policy, range of reasonableness, Bonbright and attributes of sound ratemaking and weighting appropriateness; the treatment of significant extra-provincial revenues; the addition of multi-billion dollar generation/transmission assets, marginal cost of service; impacts by class flowing from reduced government water rental fees and provincial debt guarantee fees, and the impact of sustaining capital expenditures, as well as load forecasting and customer survey matters on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2023/24 & 2024/25 General Rate Application** proceeding before the **Manitoba Public Utilities Board.**

- Conducted several reviews on the potential for cross-subsidy between the distribution and sale of natural gas at **Liberty Utilities (Gas New Brunswick) LP** for the **New Brunswick Energy & Utilities Board** for 2021, 2022 & 2023.

- Provided independent expert evidence on residential and streetlighting distribution investment policies related to four **Alberta distribution utilities (ATCO, ENMAX, EPCOR and Fortis)** on behalf of **BILD Alberta** in the **2024 Maximum Investment Levels Phase 2** proceeding before the **Alberta Utilities Commission.**

- Provide regulatory consulting services to the **British Columbia Old Age Pensioners' Organization et al** Intervenor Group in connection with numerous natural gas, thermal utility, and electric applications before the **British Columbia Utilities Commission** including:

    - **FortisBC Energy Inc. (gas):**

        - 2025 and 2026 Annual Review of Delivery Rates;
        - Regional Gas Supply Diversity Development Cost Deferral Account Recovery Application;
        - 2025 to 2027 Rate Setting Framework Application;
        - Okanagan Capacity Mitigation Project CPCN (2024);
        - 2024 Annual Review of Delivery Rates;
        - 2024 to 2027 Demand-Side Management Expenditures Plan;
        - 2023 Cost of Service Allocation & Revenue Rebalancing;
        - Interior Transmission System Transmission Integrity Management Capabilities Project CPCN;
        - 2023 Demand-Side Management Expenditures Plan
        - 2022 Long-Term Gas Resource Plan (integrated resource plan);
        - Okanagan Capacity Upgrade Project CPCN;
        - Tilbury Liquefied Natural Gas Storage Expansion Project CPCNs;
        - Biomethane Energy Recovery Charge Rate Methodology & Comprehensive Review of a Revised Renewable Gas Program; and
        - Pattullo Gas Replacement Project Certificate of Public Convenience & Necessity (CPCN).

    - **Pacific Northern Gas Ltd.**:

        - North-East Division 2025 to 2027 Revenue Requirements Application
        - West Division 2025 to 2027 Revenue Requirements Application; and
        - 2025 to 2027 Energy Conservation & Innovation Portfolio Funding Application;
        - 2024 Consolidated Resource Plan (integrated resource plan);
        - North-East Division 2023 & 2024 Revenue Requirements Application;

- West Division 2023 & 2024 Revenue Requirements Application;
- 2023 to 2024 Energy Conservation & Innovation Portfolio Funding Application;
- North-East Division 2022 Revenue Requirements Application;
- West Division 2022 Revenue Requirements Application; and
- Salvus to Galloway Gas Line Upgrade Project CPCN;

- **Creative Energy Vancouver Platforms Inc.:**

  - Senakw 2026 to 2027 Rates & Rate Design Application;
  - 2026 to 2027 Rates for Cooling at South Downtown Thermal Energy System;
  - 2024 to 2027 Rates for Heating at South Downtown Thermal Energy System;
  - New Plant Premises & Interconnection Capital Expenditure Schedule;
  - 2025 Revenue Requirements Application for the Core Steam System;
  - 2024 Revenue Requirements Application for the Core Steam System
  - 2024 Long-Term Resource Plan;
  - 2023 Revenue Requirements Application for the Core Steam System;
  - Beatty-Expo Plants Redevelopment Project Final Design;
  - Core Steam System Decarbonization Project CPCN;
  - 2021 Long-Term Resource Plan;
  - 2021 Revenue Requirements Application for the Core Steam System; and
  - 2021 Application - Thermal Energy System Heating Rates & District Cooling System Rates.

- **Corix Multiutility Services Inc.:**

  - Dockside Green District Energy System 2025 to 2028 Revenue Requirements Application;
  - UBC Neighbourhood District Energy System 2025 to 2027 Revenue Requirements Application;
  - Burnaby Mountain District Energy Utility 2024 to 2025 Revenue Requirements Application; and
  - Burnaby Mountain District Energy Utility 2020 to 2023 Revenue Requirements Application.

- **FortisBC Inc. (electric)**:

  - 2025 and 2026 Annual Review of Delivery Rates;
  - 2025 to 2027 Rate Setting Framework Application; and
  - 2023 to 2027 Demand-Side Management Expenditures Plan.

- **Nelson Hydro** - 2023 Revenue Requirements Application.
- **BC Hydro** - Enterprise Resource Planning Projects (S/4HANA & Stations SAP projects).
- **Insurance Corporation of British Columbia:**

  - 2024 Financial Allocation Methodology Review;
  - 2023 Policy Year (2023/24 & 2024/25) Revenue Requirements Application; and
  - 2021 Policy Year (2021/22 & 2022/23) Revenue Requirements Application.

- **British Columbia Utilities Commission:**

  - Review of Renewable Natural Gas Definition and Accounting;
  - Review of Thermal Energy Systems Regulatory Framework Guidelines Phase 2;
  - Inquiry into the Acquisition of Renewable Natural Gas by British Columbia Public Utilities - Phase 2; and
  - Inquiry into the Regulation of Hydrogen Energy Services.

- Provided regulatory consulting services on rate and cost allocation matters to the **Consumers Coalition** (Consumers Association of Canada (Manitoba), Aboriginal Council of Winnipeg and Harvest Manitoba) in connection with the **Manitoba Hydro 2021/22 Interim Rate Application** and associated **Review & Vary Application** before the **Manitoba Public Utilities Board**.
- Provided regulatory consulting services to the **Consumers Coalition** and **Consumers Association of Canada (Manitoba)** in connection with the **Manitoba Hydro/Centra Gas Manitoba Inc. Combined Hearing Application** - before the **Manitoba Public Utilities Board.**
- Provided independent expert evidence and advice on natural gas rate policy and cost allocation matters on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas Manitoba Inc. 2022 Natural Gas Cost of Service Review** proceeding before the **Manitoba Public Utilities Board.**
- Provided independent expert advice on ratemaking policy, rate design, ancillary cost allocation matters as well as matters of natural gas competition on behalf of the **Consumers Association of Canada (Manitoba)** in connection with the **2021 Centra Gas Rate Re-Bundling Application** before the **Manitoba Public Utilities Board.**
- Conducted a review of the potential for cross-subsidy between distribution of gas and sale of gas at **Liberty Utilities (Gas New Brunswick) LP** during 2021 for the **New Brunswick Energy & Utilities Board.**
- Provided independent expert rate advice and evidence regarding marginal and load retention rates to the **Nova Scotia Utility and Review Board** regarding **Nova Scotia Power's** 2020, 2021, 2022, and 2023 Annually Adjusted Rate Applications.
- Provided independent expert evidence and testimony to the **Nova Scotia Utility and Review Board** regarding **Nova Scotia Power's 2021 Back-Up/Top-Up Rates** related to the cost to serve and pricing of intermittently served municipally owned wind generation.
- Provided advisory services to **Efficiency Manitoba** in connection with its **2020-2023 Efficiency Plan** filing to the Manitoba Public Utilities Board (MPUB), including regulatory on-boarding, regulatory filing review process design and strategic filing preparation advice.
- Independent expert witness on ratemaking policy, internal and external cost allocation, rate design, and terms and conditions of service matters before the MPUB on behalf of the **Consumers Association of Canada (Manitoba)** in the **Centra Gas 2019/20 General Rate Application** proceeding before the **Manitoba Public Utilities Board**.
- Independent expert witness on ratemaking policy, cost of service, rate design and regulatory compliance matters before MPUB on behalf of the **Consumers Coalition** in the **Manitoba Hydro 2019/20 Rate Application proceeding**.
- Conducted a review and made recommendations on the implementation of a revised **internal cost allocation methodology** related to the inter-affiliate, multi-jurisdictional allocation of corporate and shared service costs for the **Corix Group of Companies**, a leading provider of energy, water & wastewater utilities for small to medium-sized communities across North America.
- Promoted through progressively senior analytical and managerial positions in the general area of **utility ratemaking and regulation** at the **privately-owned Centra Gas**, and then **Manitoba Hydro**, a combined publicly owned vertically integrated hydro-electric utility and disaggregated natural gas utility. A selection of relevant project experience includes:

    - Reviewed zone of reasonableness policy and developed the related strategy and evidence;
    - Addressed the treatment of International Financial Reporting Standards (IFRS) within cost of service;
    - Treatment of large hydraulic generation cost measurement within embedded cost to serve;
    - Treatment of significant export revenue priced at the margin (at times 40% or more of total revenue requirement) within embedded cost to serve (effectively a matter of public policy);
    - Treatment of demand side management cost within cost to serve;
    - Economic development rates/energy intensive rates/low income rates;

- Uneconomic bi-pass (distributed solar PV); economic bi-pass;
- Costing assumptions in feasibility tests to address divergence between embedded and marginal cost to service and related service extension policy (including to support business expansion and growth opportunities);
- Allocation treatment of revenues and costs (and related rate base) associated with unique partnerships with First Nations developed to support new, multi-billion-dollar hydraulic generation;
- Wheeling tariffs—provided the underlying cost analysis and regulatory advice;
- Treatment and determination of variance accounts (cost trackers);
- Led Revenue Decoupling evidence and testimony during the 2007-08 Centra GRA;
- Evaluated the appropriateness and level of Month Basic Charges, developed evidence and led testimony;
- Evaluated the appropriateness and level of Demand Charges, developed evidence and led testimony;
- Fixed rate alternatives (within and outside of regulated utility);
- Successfully developed a solution for and executed the disposal of $100 million in gas costs (nearly 40% of total asset investment) accumulated during the natural gas market conditions in early 2001, and the accumulation of $46 million in gas costs during the 2013/2014 record cold winter;
- Rate unbundling to support service unbundling flowing from natural gas market restructuring to facilitate competition;
- Analysis and research assessing a competition-related role of the utility in the provision of gas supply application;
- Successfully developed a treatment for costs incurred to facilitate competition; and
- Developed codes of conduct between regulated and unregulated utility affiliates.