IN THE MATTER OF the *Electrical Power Control Act,* 1994, SNL 1994, Chapter E-5.1 and the *Public Utilities Act,* RSNL 1990, Chapter P-47, and regulations thereunder; and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2027.

CONSUMER ADVOCATE
AMENDED SECOND ROUND REQUESTS FOR INFORMATION
CA-PUB-001 to CA-PUB-019

Issued: November 13, 2026

A. Cost Allocation and Rate Design

CA-PUB-001 COS Methodologies and Interclass Equity

NLH's 2027 Test Year reflects a fundamental transformation of its integrated electricity system following the introduction of Muskrat Falls generation and the Labrador-Island Link. These investments have substantially increased the costs of supplying electricity, with NLH's revenue requirement increasing from approximately $643 million in 2019 to $1.3 billion in 2027, before rate mitigation.

The magnitude of these costs has necessitated extraordinary government-imposed rate mitigation measures, reducing the 2027 revenue requirement by approximately $502 million to moderate the resulting rate impacts on customers.

Notwithstanding these circumstances, NLH proposes a 14.3% reduction in Island Industrial rates.

The following questions concern the principles governing the allocation of common generation costs, the resulting changes in relative class cost responsibility, and the appropriateness of the proposed Industrial rate adjustment.

a) Does Brattle agree that more than one technically supportable methodology may exist for the classification and allocation of common generation costs, depending on the interpretation and application of cost causation principles. Please explain.

b) What criteria should inform the selection among alternative, technically supportable methodologies, particularly where the alternatives produce materially different allocations of common costs among customer classes.

c) In Brattle's view, how should the purpose of the underlying investments and the implications of alternative COS methodologies for interclass equity and longer-term class cost responsibility be considered when selecting an appropriate methodology. To what extent should considerations such as rate stability and gradualism instead be addressed through subsequent class revenue allocation and rate-setting decisions.

d) Please identify relevant regulatory proceedings in which Brattle or the authors of its report have provided expert evidence addressing the selection among alternative COS methodologies and the associated implications for interclass cost responsibility. Please provide references to the relevant evidence.

e) In Brattle's view, to what extent does a substantial change in the relative allocation of common generation costs among customer classes, arising principally from the transition from thermal to hydraulic generation and the associated changes in cost classification, reflect a corresponding change in the underlying cost responsibility of those classes. In particular, where the resulting redistribution of costs is materially greater than any change in the relative loads or demands of the customer classes, what considerations should inform the assessment of whether the resulting class cost allocations appropriately reflect cost causation and interclass equity.

CA-PUB-002 COS Methodologies and Interclass Equity

NLH's 2027 Test Year reflects a fundamental transformation of its integrated electricity system following the introduction of Muskrat Falls generation and the Labrador-Island Link. These investments have substantially increased the costs of supplying electricity, with NLH's revenue requirement increasing from approximately $643 million in 2019 to $1.3 billion in 2027, before rate mitigation.

The magnitude of these costs has necessitated extraordinary government-imposed rate mitigation measures, reducing the 2027 revenue requirement by approximately $502 million to moderate the resulting rate impacts on customers.

Notwithstanding these circumstances, NLH proposes a 14.3% reduction in Island Industrial rates.

a) In Brattle's view, what considerations should inform the Board's assessment of whether NLH's proposed 14.3% Industrial rate decrease represents a fair and reasonable outcome in circumstances involving substantial new common generation and transmission investments, a significant increase in the overall revenue requirement and extraordinary government-imposed rate mitigation.

b) Does Brattle consider that achieving an RCC of approximately 1.0 under the 2027 COS study is sufficient, in itself, to establish the appropriateness of implementing the full Industrial rate decrease. Please explain.

c) Has Brattle evaluated the appropriateness of the proposed Industrial rate decrease, as distinct from its assessment of Industrial rate design. If so, please provide its analysis and conclusions. If not, please explain whether Brattle considers such an assessment necessary to evaluate the proposed Industrial rate decrease.

d) Where changes in generation cost classification and allocation methodologies result in a material reduction in the costs allocated to a particular customer class, to what extent does that reduction, in itself, justify an absolute decrease in the class's rates. What other considerations should inform the appropriateness and magnitude of such a decrease, particularly where the utility's overall cost of service has increased substantially and significant rate mitigation is required to moderate customer rate impacts.

CA-PUB-003 Change in Generation Resources and Relative Class Cost Responsibility

NLH's 2027 Test Year reflects a fundamental transformation of its integrated electricity system following the introduction of Muskrat Falls generation and the Labrador-Island Link. These investments have substantially increased the costs of supplying electricity, with NLH's revenue requirement increasing from approximately $643 million in 2019 to $1.3 billion in 2027, before rate mitigation.

The magnitude of these costs has necessitated extraordinary government-imposed rate mitigation measures, reducing the 2027 revenue requirement by approximately $502 million to moderate the resulting rate impacts on customers.

Notwithstanding these circumstances, NLH proposes a 14.3% reduction in Island Industrial rates.

a) What role does Brattle consider RCCs should play in determining class rates, recognizing the assumptions, judgments and potential variability inherent in embedded COS studies.

b) Beyond the inherent limitations and approximations of cost-of-service studies, what other ratemaking objectives and considerations support the use of a Range of Reasonableness (ROR) in establishing class revenue responsibilities. How should those considerations inform the selection of an appropriate ROR.

c) Under what circumstances, if any, would Brattle consider it appropriate to implement class rate adjustments gradually, or to establish rates resulting in RCCs outside a conventional Range of Reasonableness, rather than immediately implementing the full COS-indicated adjustments.

CA-PUB-004 Proposed COS Methodology – Holyrood

Reference: Brattle Report, Section I.A, pg. 10–12.

Brattle recommends classifying 93.06% of Holyrood's forecast No. 6 fuel costs as demand-related, on the basis that the associated minimum generation is required to maintain units online for system reliability.

a) Given that fuel is consumed in producing electrical energy, please explain what cost-causation principles support classifying Holyrood's fuel costs as demand-related rather than energy-related. In particular, how does Brattle distinguish between the reliability requirement that causes a generating unit to be committed and the energy produced while that unit remains online.

b) Given that natural gas is priced in commodity markets on an energy basis, notwithstanding the substantial fixed costs associated with its production, please explain what distinguishes the cost-causation principles underlying the treatment of natural gas as an energy commodity from those supporting the classification of Holyrood's fuel consumption as demand-related.

c) Does Brattle consider that the classification of fuel costs should reflect the operating role of the generating resource in the particular test year, or the underlying purpose and longer-term responsibility for maintaining the resource as part of the integrated system. Please explain how these considerations were reflected in its recommendation.

d) To what extent is Brattle's recommended demand/energy classification of Holyrood fuel costs sensitive to changes in operating conditions, including hydraulic conditions, reliability requirements and generation dispatch. Please explain whether material changes in these conditions could warrant a different classification in future test years.

CA-PUB-005 Holyrood Non-Fuel Classification and Energy Allocation

Reference: Brattle Report, Section I.B; Order P.U. 37(2019), Schedule A, paragraph 20.

Brattle recommends reducing the energy classification of Holyrood's non-fuel costs from approximately 11.16% to 0.8% by excluding generation at minimum stable output from the capacity-factor numerator. Brattle also recommends allocating the remaining energy-related costs using customer energy consumption during Holyrood's commitment period rather than annual energy consumption.

a) Please explain the cost-causation basis for excluding generation at minimum stable output from the capacity-factor numerator when classifying Holyrood's non-fuel costs, including how this approach reflects the purpose of the underlying investment in generating capacity.

b) Please explain what specific cost-causation considerations lead Brattle to conclude that its proposed capacity-factor calculation, resulting in an energy classification of approximately 0.8%, is more appropriate than the alternative calculations identified in its report. As part of the response, please identify the principal shortcomings of those alternatives.

c) Please explain the cost-causation basis for allocating Holyrood's energy-related fixed generation costs using customer energy consumption during the plant's forecast commitment period rather than annual energy consumption.

d) How would the proposed commitment-period allocation respond to changes in Holyrood's seasonal operating requirements, and what implications could this have for the stability of relative class cost responsibility over time.

CA-PUB-006 Holyrood's Capacity and Firm-Energy Requirements

References: Brattle Report, Section I.B, pp. 10–12; CA-NLH-156(d); CA-NLH-158, pgs. 1–3; Order P.U. 37(2019), Schedule A, paragraph 20.

Brattle recommends classifying approximately 99.2% of Holyrood's non-fuel generation costs as demand-related, with the remaining 0.8% classified as energy-related, based on forecast generation above minimum stable output in the 2027 Test Year.

In CA-NLH-156(d), NLH confirms that while the Island Interconnected System's firm-energy requirements can be met without Holyrood under average hydrological conditions, existing and committed resources would be insufficient to meet those requirements during a critical dry sequence or other severe drought period without Holyrood.

In CA-NLH-158, NLH further confirms that its 2027 production plan assumes average Island inflows and does not incorporate additional Holyrood generation required to support reservoir storage during drought conditions. NLH reports that drought conditions in 2025 required an additional 130.5 GWh of Holyrood generation during September–November, notwithstanding maximized LIL deliveries and additional Maritime Link imports.

These circumstances raise questions concerning whether a demand/energy classification based on forecast generation under average hydrological conditions adequately reflects Holyrood's continuing role in meeting both capacity and firm-energy requirements.

a) In determining the demand/energy classification of generation costs for an embedded COS study, how should the need to maintain generating capability to meet firm-energy requirements under periodically occurring adverse hydrological conditions be reflected, where those requirements are not captured by forecast generation under average test-year conditions. As part of the response, please explain whether the classification should reflect the operating conditions forecast for the test year, the underlying capacity and firm-energy requirements for which the facility is maintained, or some combination of these considerations.

b) Applying these principles to Holyrood, please explain how Brattle's recommended classification of approximately 99.2% of non-fuel costs as demand-related appropriately recognizes NLH's confirmed reliance on Holyrood to meet firm-energy requirements during critical dry sequences, notwithstanding that the 2027 Test Year production forecast assumes average hydrological conditions.

c) In developing its recommended classification, did Brattle assess the extent to which Holyrood's generating facilities and associated expenditures would be required to meet capacity and reliability requirements independently of its firm-energy requirements, and conversely, the extent to which those facilities and expenditures are required to meet firm-energy requirements. If so, please provide the analysis and explain how costs supporting both functions were considered. If not, please explain how Brattle determined that approximately 99.2% of Holyrood's non-fuel costs should be classified as demand-related.

d) Given the additional 130.5 GWh of Holyrood generation required during the 2025 drought conditions, has Brattle assessed the sensitivity of its recommended demand/energy classification to adverse hydrological conditions. If so, please provide the results. If not, please explain whether materially greater generation under such conditions would warrant a different classification and how this consideration affects the appropriateness of the proposed methodology for the 2027 COS Study.

CA-PUB-007 Holyrood Unit 3 Functionalization

Reference: Brattle Report, Sections I.A and I.B; Order No. P.U. 37(2019), Schedule A, paragraphs 7, 10, 12, 20 and 30; NLH's 2025 Near-Term Reliability Report, Section 3.2.1; Order P.U. 2(2026), Section 4.1.4.

Order P.U. 37(2019) accepted the recommendations of the 2019 Cost of Service Methodology Settlement Agreement. Paragraph 7 establishes the agreed methodology for use in the first GRA addressing recovery of Muskrat Falls Project costs, subject to specified matters for further review.

Paragraph 12 provides that Holyrood Unit 3 shall be functionalized as transmission after permanent conversion to synchronous condenser operation. Paragraph 30 provides for the continued allocation of energy costs based on annual energy consumption by customer class.

a) Please identify which of Brattle's recommendations concerning Holyrood fuel classification, non-fuel classification, energy allocation and Unit 3 functionalization are consistent with the methodology established under Order P.U. 37(2019), and which represent departures from that methodology.

b) For each departure identified in part (a), please explain the basis upon which Brattle considers it appropriate to recommend a change in the current GRA, having regard to paragraph 7 of the Settlement Agreement and the Board's acceptance of the agreed methodology.

c) Please confirm whether Holyrood Unit 3 has been permanently converted to synchronous condenser operation. If not, please explain the basis for Brattle's recommendation to functionalize Unit 3 operating costs as transmission during periods of synchronous condenser operation, notwithstanding the permanent-conversion condition in paragraph 12 of the Settlement Agreement.

d) In developing its recommendation concerning Holyrood Unit 3, what consideration did Brattle give to NLH's continuing reliance on Holyrood for generation, including the planned retention of generating capability and associated capital expenditures identified in NLH's 2025 Near-Term Reliability Report and Order No. P.U. 2(2026). Please explain whether these circumstances affect Brattle's recommendation and how Brattle distinguishes costs incurred to maintain generating capability from costs specifically attributable to synchronous condenser operation.

e) Please identify the categories and amounts of Unit 3 costs Brattle proposes to functionalize as transmission, the proposed allocation methodology, and the cost-causation basis for distinguishing those costs from costs associated with maintaining Unit 3's generating capability.

CA-PUB-008 Impacts of Holyrood Recommendations

Reference: Brattle Report, Sections I.A and I.B

a) Please provide the expected directional impacts of each of Brattle's recommendations concerning Holyrood fuel classification, non-fuel classification, energy allocation and Unit 3 functionalization on the allocation of costs among Newfoundland Power, Island Industrial and Rural customers, relative to NLH's proposed 2027 COS Study. Please provide material assumptions and caveats.

b) Please indicate whether the combined effect of Brattle's recommendations would be expected to increase or decrease the allocated costs and RCCs of each customer class, and whether Brattle considers the combined effects potentially material to the COS-indicated class revenue adjustments.

c) Please explain whether Brattle quantified the individual or combined class impacts of its recommendations. If so, please provide the results, including the impacts on allocated costs and RCCs. If not, please confirm.

CA-PUB-009 Classification of Holyrood

Reference: Bowman Evidence, pg. 20–22; Brattle Report, Section I.B; NLH 2025 Near-Term Reliability Report, Section 3.2.1; Order P.U. 37(2019), Schedule A, paragraph 20

NLH's 2025 Near-Term Reliability Report (Section 3.2.1, page 20) states that NLH plans to retain Holyrood TGS through April 2030, or until sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link is demonstrated, and generation reserve requirements are met. Accordingly, NLH considers all three Holyrood units operational from 2026 through April 2030.

Mr. Bowman recommends classifying 100% of Holyrood's plant-related costs as demand-related, based on his assessment of the plant's operating role in the 2027 Test Year.

a) Having regard to NLH's planned operating role for Holyrood during the 2027–2030 period, does Brattle agree with Mr. Bowman's recommendation to classify 100% of Holyrood's plant-related costs as demand-related, rather than retaining an energy-related component under the capacity-factor methodology established in the 2019 COS Methodology Settlement Agreement. Please explain the cost-causation basis for its conclusion.

b) Please explain whether Brattle considers that Holyrood's continued role in generating energy under certain system conditions warrants retaining an energy-related component of its plant costs.

CA-PUB-010 Appropriateness of Generation COS Methodology Following Muskrat Falls

Reference: Brattle Report; Bowman Evidence, Recommendation 3; Order P.U. 37(2019), Schedule A, paragraph 29.

Paragraph 29 of the 2019 COS Methodology Settlement Agreement provides for the continued use of the single coincident peak (1CP) methodology to allocate production/generation demand costs and transmission costs among customer classes. The Agreement also contemplated further review of the contribution of customer classes to the uncertainty parameters used in NLH's system planning studies, including P50 versus P90 assumptions.

With the commissioning of the Muskrat Falls Project and the Labrador-Island Link, NLH's generation portfolio has undergone a fundamental transformation. The resulting supply portfolio includes substantial long-term generation commitments incurred to meet capacity, energy and system reliability requirements, including reliability considerations associated with adverse hydraulic conditions.

a) In Brattle's view, does the continued use of a 1CP allocator appropriately reflect the underlying cost causation associated with NLH's post-Muskrat Falls

generation portfolio, particularly where generation investments serve capacity, energy and reliability requirements extending beyond the annual system peak and support electricity exports. As part of the response, please explain how the ongoing utilization of these resources for domestic supply and export sales should be considered in assessing the appropriateness of the allocation methodology.

b) In assessing the reasonableness of the 2027 COS Study and the allocation of generation-related costs among customer classes, has Brattle considered whether the continued use of 1CP appropriately reflects the cost causation associated with NLH's post-Muskrat Falls generation portfolio, relative to alternative demand allocators such as 2CP, 4CP or 12CP. In particular, please address the significance of hydraulic conditions, generation availability and ongoing utilization in assessing the appropriateness of the demand allocation methodology applied in the current GRA.

c) The approved COS methodology classifies both Muskrat Falls Project costs and net export revenues using system load factor, with net export revenues reducing the supply costs recovered from Island Interconnected customers. In assessing the reasonableness of the 2027 COS results, to what extent has Brattle considered the interrelationship between domestic electricity requirements, ongoing generation utilization, hydraulic conditions, export market opportunities and the associated costs and revenues. Please explain how these factors influence the ultimate net cost of serving NLH's domestic customer classes and the interpretation of the resulting class cost allocations.

d) Mr. Bowman recommends that demand-related costs be allocated using class coincident peak demands based on P90 rather than P50 load conditions, citing NLH's need to plan for more extreme conditions.

Given the significant role of hydraulic generation in NLH's post-Muskrat Falls supply portfolio, does Brattle consider that the use of P90 peak demand appropriately reflects the underlying cost causation associated with generation capacity requirements, including the need to maintain reliable supply under adverse hydraulic conditions. Please explain whether the use of P90 peak demands provides a more appropriate basis for allocating generation demand costs among customer classes than the existing P50 methodology.

CA-PUB-011 Allocation of Demand-Related LTSCVDA Balances

Reference: Bowman Evidence, pg. 11–12, Recommendations 1 and 2; PUB-NLH-086(a); Brattle Report

Mr. Bowman recommends that demand-related balances in the Long-Term Supply Cost Variance Deferral Account (LTSCVDA) be allocated at year-end based on each customer class's measured contribution to the annual coincident system peak (1CP), rather than the billing-demand measures proposed by NLH.

a) Does Brattle agree that annual 1CP provides a more appropriate cost-causation basis for allocating demand-related LTSCVDA balances than NLH's proposed billing-demand methodology. Please explain, having regard to the nature of the

costs and variances recorded in the account, rather than solely to consistency with the approved COS methodology.

b) To what extent do the supply cost variances recorded in the LTSCVDA arise from factors other than annual peak demand, including hydraulic conditions, generation availability, changes in energy requirements and other system operating conditions. In Brattle's view, does allocation based on a single annual coincident peak appropriately reflect the relative responsibility of customer classes for the balances being recovered or refunded. Please explain.

c) Has Brattle assessed the interclass allocation consequences of adopting Mr. Bowman's recommendation rather than NLH's proposed methodology. If so, please provide the results for Newfoundland Power, Island Industrial and Rural Island Interconnected customers. If not, please indicate whether the proposed change could materially alter the allocation of LTSCVDA balances among these classes and the basis for Brattle's assessment.

CA-PUB-012 LTSCVDA Interclass Allocation Implications

Reference: Brattle Report, pg. 26–32; NLH 2026 GRA, Volume I, Section 5.7.5; NLH 2026 GRA, Exhibit 10, LTSCVDA

The proposed Long-Term Supply Cost Variance Deferral Account (LTSCVDA) would protect NLH's earnings from specified load-related revenue variances, net of offsetting export revenues, by recording those variances for subsequent recovery from, or refund to, customers. The resulting balances would be classified between demand and energy using system load factor (SLF) and allocated among customer classes using the corresponding demand and energy allocation determinants.

Brattle has expressed concern that variances recorded in the LTSCVDA should be classified consistently with the 2027 Test Year COS treatment of the amounts being corrected, to avoid shifting costs among customer classes solely because actual results differ from forecast. Brattle has also recommended using coincident peak demand rather than billing demand for allocating the demand-related component.

The following questions seek to examine the interclass allocation implications of NLH's proposed LTSCVDA methodology and Brattle's recommended modifications, including the extent to which the resulting allocations reflect the underlying cost drivers and the treatment of offsetting export revenues.

a) Assuming a $10 million net balance recorded in the LTSCVDA arising from lower-than-forecast Island Industrial load, after accounting for offsetting export revenues, please provide a sensitivity on how the shortfall would be allocated among Newfoundland Power, Island Industrial and Rural Island Interconnected customers under Brattle's recommended methodology. For this hypothetical assume proportionate reductions in Industrial energy consumption, billing demand and coincident peak demand relative to forecast with all other assumptions held constant. Please provide a table showing the 2027 COS allocated costs by class, the resulting allocation of the $10 million balance ($ and %), and the principal reasons for material differences among classes.

b) In Brattle's view, to what extent would the allocation of a net Industrial load-related revenue variance among customer classes under either methodology reflect the underlying cost causation of the variance, including the effect of offsetting export revenues. Please explain.

c) Would Brattle's assessment differ if incremental export revenues associated with lower-than-forecast Island Industrial load exceeded the corresponding reduction in Industrial revenues, resulting in a net $10 million credit to the LTSCVDA. Please explain whether the allocation methodology and resulting interclass cost-causation considerations would differ from those applicable to the net revenue shortfall described in part (a).

CA-PUB-013 LTSCVDA: Valuation of Load Variations and Offsetting Export Revenues

Reference: Brattle Report, pg. 28–30, Finding 3, Table 3; CA-NLH-290, Table 2; NLH 2026 GRA, Volume I, Section 5.7.5; NLH 2026 GRA, Volume III (Revision 1), Exhibit 10, Section 8.0

Brattle identifies a concern with the different prices used to value load variations and offsetting export revenues under the proposed Long-Term Supply Cost Variance Deferral Account (LTSCVDA). Specifically, Brattle notes that Island Industrial load variations are valued using seasonal second-block energy rates, while offsetting export revenues are valued using an annual average export price.

Brattle recommends that NLH either value load variations on the same basis as the offsetting export revenues, consistent with the Annual Average Sales Price prescribed under the Muskrat Falls Power Purchase Agreement, or explain why customers should bear the difference.

In response to CA-NLH-290, NLH provided hypothetical sensitivities involving 10% and 25% reductions in Island Industrial load, including the resulting changes in billing revenues, incremental export revenues and net revenue impacts, assuming NLH's proposed methodology.

The following questions seek to clarify the implications of Brattle's findings for the measurement of net revenue variances and the amounts recorded in the LTSCVDA.

a) Please clarify whether Brattle's concern with the different valuation bases relates primarily to an inconsistency in the underlying methodology or whether Brattle considers that NLH's proposed approach may materially overstate or understate the net financial impact of load variations recorded in the LTSCVDA. Please explain.

b) Using the hypothetical 10% and 25% reductions in Island Industrial load presented in CA-NLH-290, Table 2, please recalculate the resulting net LTSCVDA balances by applying Brattle's recommended valuation basis to the load variations, while retaining the other assumptions underlying NLH's calculations. Please provide a table comparing the results with NLH's calculations and identify the principal reasons for any differences. To the extent Brattle is unable to prepare the requested analysis, please explain the reasons and

provide a qualitative assessment of the anticipated direction and magnitude of the differences, including the principal factors influencing the results.

c) Please explain whether the use of a common valuation basis for load variations and offsetting export revenues would more accurately reflect the actual net economic impact on NLH of changes in Island Industrial load, recognizing that domestic billing revenues and incremental export revenues may differ due to rate design, seasonal pricing and contractual arrangements governing export revenues.

CA-PUB-014 Relationship Between Demand/Energy Cost Classification and Industrial Rate Design

Reference: Brattle Report, pgs. 34–44, Finding 2; NLH 2026 GRA, Volume I, Section 6.7

Brattle observes that, under NLH's proposed Island Industrial hours-of-use rate design, approximately 31% of costs classified as demand-related in the 2027 Cost of Service Study would be recovered through the demand charge, with the remaining 69% recovered through an energy charge. Brattle expresses concern regarding the cost reflectivity of this approach, which may weaken cost-reflective price signals, and recommends consideration of a demand charge that more fully recovers demand-related costs.

At the same time, Brattle also acknowledges that average embedded energy costs and marginal energy costs have diverged substantially following interconnection.

The 2027 COS Study classifies Muskrat Falls Project costs between demand and energy using the approved system load factor methodology, resulting in approximately 49.71% demand and 50.29% energy classification.

a) In assessing the cost reflectivity of the proposed Industrial rate design, how does Brattle distinguish the objectives of demand/energy classification for embedded COS allocation from the objectives of demand and energy charges in providing price signals. Please explain whether, and in what circumstances, the proportions of costs classified as demand- and energy-related should inform the proportions recovered through each charge.

b) To what extent should the dependable capacity contribution of a generating resource, as distinct from its contribution to meeting firm energy requirements, determine the proportion of its costs classified as demand-related for COS purposes. In particular, how has Brattle considered the relative importance of capacity requirements and firm energy requirements in assessing the appropriateness of the demand/energy classification of Muskrat Falls costs and its implications for the proposed Industrial rate design.

c) Has Brattle considered whether the relationship between the marginal costs of serving incremental Industrial demand and energy requirements and the embedded COS classification has changed following interconnection, including the utilization of generation resources and export opportunities. If so, please describe the analysis and implications for Industrial rate design. If not, please explain whether such an assessment is necessary to support its recommendations.

CA-PUB-015 Canadian Regulatory Practice Regarding Range of Reasonableness

Reference: NLH 2027 COS and Rate Design Study; Derksen Evidence, Section 5.4; CA Energy Review of MH COS, June 8, 2012, pgs. 32–36

In its June 8, 2012 review of Manitoba Hydro's cost-of-service methodologies, Christensen Associates Energy Consulting discussed the role of embedded COS studies in determining class cost responsibility and rate levels, including the application of Ranges of Reasonableness (RORs) around revenue-to-cost coverage ratio (RCC) unity.

Christensen observed that the acceptance of departures from RCC unity recognizes both the limitations of fully distributed cost allocation in attributing common costs and the relevance of fairness and other ratemaking considerations. Christensen also indicated that marginal-cost considerations may inform target class RCCs and acceptable RORs, including the selection of targets within those ranges.

a) Recognizing that the use of a Range of Reasonableness around RCC unity is a widely accepted practice in Canadian electric utility regulation, is Brattle aware of any Canadian electric utility regulatory proceedings in which the regulator has expressly rejected the use of an ROR in establishing class revenue responsibilities. If so, please identify the proceedings, the reasons for rejecting an ROR, and the relevant regulatory determinations.

b) Does Brattle consider the application of an ROR to be an appropriate rate-setting approach for NLH in the circumstances of the 2026 GRA, particularly given the significant changes in NLH's supply costs, the resulting shifts in class cost responsibilities, and the substantial shared generation and transmission infrastructure supporting domestic supply and export opportunities. Please explain the considerations supporting its position.

c) In Brattle's view, how should a regulator assess an appropriate ROR where a utility has undergone a fundamental transformation in its generation supply, resulting in material changes in the classification and allocation of substantial shared generation and transmission costs among customer classes. In particular, should material changes in class RCCs arising from changes in generation resources and associated cost classification and allocation be considered when determining the appropriate width and application of an ROR, particularly where those changes are not accompanied by comparable changes in customer load characteristics or usage. Please explain.

d) Does Brattle agree with Christensen Associates that marginal-cost considerations may appropriately inform the determination of target class RCCs and acceptable RORs, including circumstances in which a target RCC other than 1.00 may be warranted. If not, please explain.

e) Did Brattle consider the application of a Range of Reasonableness in its review of NLH's 2027 COS Study, particularly in assessing the implications of the resulting class RCCs for NLH's proposed rate adjustments, including the 14.3% decrease in Island Industrial rates. If not, please explain why it was not considered and whether Brattle considers the absence of such an assessment to

be a limitation in evaluating the reasonableness of the proposed class rate adjustments.

CA-PUB-016 Relative Recovery of Unmitigated Costs

Reference: Brattle Report, findings and recommendations concerning the 2027 COS Study; Derksen Evidence, Section 7.1; PUB-NLH-105

a) In Brattle's view, should the assessment of interclass equity and proposed class rate adjustments consider both the RCCs calculated under the mitigated 2027 COS Study and the proportion of each class's underlying unmitigated allocated costs recovered through proposed revenues. As part of the response, please explain the relevance and limitations of each measure, particularly where substantial rate mitigation is required and the proportion of unmitigated costs recovered differs materially among customer classes.

CA-PUB-017 Newfoundland Power Hydraulic Credit

Reference: Brattle Report, Newfoundland Power Hydraulic Credit

a) Given Brattle's view that the existing five-year averaging approach does not vary with peak severity, did Brattle assess alternative methodologies that explicitly account for peak severity or hydraulic conditions. If so, please identify the alternatives considered and explain why they were not recommended.

b) Has Brattle quantified the effect of its recommended methodology relative to NLH's proposed methodology on Newfoundland Power's hydraulic credit and the resulting class cost allocations in the 2027 COS Study. If yes, please provide a summary of the results.

CA-PUB-018 Export Revenues, Marginal Costs and Interclass Equity

Reference: Brattle Report, Assessment of LTSCVA; CA-NLH-337; Derksen Evidence, Sections 4.5 and 6.1

a) In the event where actual net export revenues differ materially from forecast, to what extent does the allocation of the resulting variances through the LTSCVDA appropriately reflect the cost causation and relative benefits attributable to the respective customer classes. In Brattle's view, are there circumstances in which the allocation of these variances should differ from the allocation of forecast export revenues in the COS Study.

b) In the event where export market prices are materially higher than forecast, how should the resulting potential increase in the opportunity cost of electricity be considered in evaluating the economic efficiency of domestic rate structures, particularly the marginal energy prices applicable to Island Industrial customers.

c) In Brattle's view, what considerations should inform the assessment of Industrial energy rates where the marginal opportunity cost of electricity, as reflected in

foregone net export revenues, materially exceeds the embedded cost of supplying that electricity. Please distinguish between the recovery of embedded costs through the COS Study and the provision of economically efficient marginal price signals through rate design.

CA-PUB-019 RCC Unity and Rate Adjustments Through 2030

Reference: NLH's proposed Annual Rate Adjustments for 2028–2030.

NLH is proposing to establish class rates based on the 2027 COS Study, including a 14.3% reduction in Island Industrial rates, but does not propose to update the COS Study or reassess class RCCs as part of its annual rate adjustments for 2028 through 2030.

a) In Brattle's view, what weight should be placed on achieving RCCs at unity in 2027 when NLH is not proposing to recalculate those ratios or maintain unity over the subsequent three years.

b) Does Brattle consider that the absence of updated COS studies and RCCs during 2028–2030 provides additional justification for considering a Range of Reasonableness and gradualism in establishing the initial 2027 class rate adjustments, rather than implementing the full rate changes indicated by the 2027 COS Study. Please explain.

DATED at St. John's, Newfoundland and Labrador, this 13th day of November, 2026.



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