STEWART McKELVEY
LAWYERS • AVOCATS

Cabot Place, 1100 – 100 New Gower Street, P.O. Box 5038
St. John's NL A1C 5V3 Canada tel: 709.722.4270 fax: 709.722.4565 stewartmckelvey.com

Dana Constantine
Direct Dial: 709.570.5790
drconstantine@stewartmckelvey.com

July 28, 2026

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

Attention: Mr. Mike McNiven, Board Secretary

Dear Mr. McNiven:

**Re: Newfoundland and Labrador Hydro 2026 General Rate Application
Requests for Information of the Island Industrial Customer Group**

On behalf of the Island Industrial Customer Group, please find enclosed Requests for Information IIC-NLH-001 to IIC-NLH-025, dated July 28, 2026, in relation to the above-noted Application.

We trust this is in order.

Yours truly,

Stewart McKelvey

Dana Constantine

Dana Constantine

DC/bm

Enclosures
c. Glen G. Seaborn
Denis J. Fleming

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

Newfoundland and Labrador Hydro
Shirley Walsh
Daniel Simmons
NLH Regulatory

4154-4349-2971

Newfoundland Power Inc.
Dominic Foley
Douglas Wright
Liam O'Brien
NP Regulatory

Consumer Advocate
Adrienne H. Y. Ding
Justin W. King, O'Dea Earle
Consumer Advocate General

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

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

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.

REQUESTS FOR INFORMATION OF THE ISLAND INDUSTRIAL CUSTOMER GROUP

IIC-NLH-001 – IIC-NLH-025

ISSUED: July 28, 2026

IIC-NLH-001 **Application, Volume I, Section 6.7 Rates for Island Industrial Customers**

Hydro states that the purpose of the September 30, 2019 Wholesale and Island Industrial Rate Design Review Update Report was to consider rate design changes that may be required upon full commissioning of the Muskrat Falls Project and Hydro's marginal cost of energy moving from No. 6 fuel to the opportunity cost of the market value of exports. Hydro's proposed rate is based on an hours of use rate design.

(a) Did Hydro consider any additional or alternative rate designs for the industrial customers?

(i) If yes, please detail which options were considered and provide copies of any reports or studies completed regarding those options.

(ii) If other options were considered and rejected, please describe on what basis those options were rejected.

(iii) If alternative rate designs were not considered, please explain why.

(b) Please indicate which Canadian electric utilities have implemented a rate design based on the hours of use model.

(i) Please provide details of the existing tariffs for the utilities using this model.

(c) Please provide references to Canadian electric utilities that have implemented a rate design based on the hours of use model, including references to existing tariffs.

IIC-NLH-002 **Application, Volume I, Section 6.7 Rates for Island Industrial Customers; Application Volume III, Christensen Associates Report Tables 1-4.**

Hydro states at page 6.18 that under its proposed rate structure, customers who manage their demand effectively and achieve a high load factor would increase their amount of energy use billed on the lower-cost Second Block Energy rate.

At page 10 of Exhibit 17, Table 1 shows the load factors of each industrial customer, with Customers 3 and 5 having the lowest load factors. Table 4 (p 13) appears to indicate that for the option currently proposed by Hydro of a demand charge of $5.50 per kW and 300 hours of use (“HOU”), the lowest load factor customers will experience decreases in bills compared to current rates, while the higher load factor customers would experience bill increases. With this in mind, please:

(a) Confirm the proposed Second Block Energy rate is higher in the winter months.

(b) Indicate whether Hydro views its proposed rate structure as improving economic efficiency as compared to its current rates and considering that the proposed rate appears to reward lower load factor customers at the expense of higher load factor customers. Please provide a detailed explanation for this conclusion.

IIC-NLH-003 **Application, Volume I, Table 6-5, Section 6.6.5 2027 Forecast Seasonal Export Prices and Section 6.7 Rates for Island Industrial Customers; Application, Volume III, Exhibit 17, Section 3, Assumptions.**

Hydro states at Footnote 29 on page 6.21 that the second block prices were calculated by CA Energy using Hydro’s forecast export prices and that differences in the resulting rates for the utility rate charge to Newfoundland Power and the Island Industrial customers are due to load profiles.

The Christensen Associates Report states at page 8 that the Block 2 energy price was calculated based on forecasted export prices on both an annual and seasonal basis with winter covering December through March and all other months being regarded as non-winter and that the pattern of export prices confirms that this seasonal division is sensible.

(a) Please confirm if the winter average (December – March) of 8.958 cents per kWh is the simple average of the values for December, January, February, and March. If not, please explain the basis of the calculation.

(i) Please provide the monthly values that lead to the 8.958 cents per kWh value, and the calculations to yield 8.958 cents per kWh.

(b) Please provide a version of Table 6-5 showing the monthly prices used to calculate the proposed winter second block energy charge for Island Industrial customers of 8.889 cents/kWh.

(c) Please elaborate on the reasons why March is included as a winter month when the prices in Table 6-5 for March are less than half the prices for January, February and December and much closer to the prices in the non-winter months.

(i) Please explain the implications if March is included as a non-winter month.

IIC-NLH-004 **Application, Volume I, Section 6.7 Rates for Island Industrial Customers.**

Hydro states a customer with a 100% load factor records 720 hours of use in a thirty-day month. Section 6.7.2 states the first block energy rate is based on a 300-hours of use block boundary.

(a) Does Hydro propose to use a 300-hour block regardless of whether a particular billing cycle is longer or shorter than 30 days?

(b) Would Hydro prorate the hours in billing cycles that are longer or shorter than 30 days?

IIC-NLH-005 **Application, Volume III, Exhibit 17, Christensen Associates Report, page 3.**

The Christensen Associates Report states the HOU design is attractive to rate designers in the sense that efficient pricing of incremental load can be achieved despite the fact that the utility is recording just two quantities per month: peak kW and total kWh. Further improvement in price efficiency requires movement to time-varying pricing.

(a) Did Hydro consider any time-varying pricing rate designs that included daily or weekly peak and off-peak prices? If not, why?

(b) What were the results of that analysis?

IIC-NLH-006 **Application Volume III, Exhibit 17, Christensen Associates Report Tables 1 to 4; Application Volume I, Table 6-9: Customer Rate Impacts – Proposed July 1, 2027 Rate.**

(a) Please confirm if the total forecasted load used as the basis for Tables 1 through 4 is the 2026 forecast load. If not, please explain how the baseline data in Table 1 were derived.

(b) Please provide versions of the Table 6-9 in the same format of Schedule 1, Appendix B from Hydro’s January 15, 2025 Application for Approval of the Island Industrial Customer Rate Adjustments Effective January 1, 2025 (PDF pages 20 through

26, including separate tables for each customer), redacting the identity of the Industrial Customer from the publicly filed response, and showing:

(i) Firm Energy forecast for 2027 broken out into three rows:

(A) First Block Energy

(B) Second Block 2 – Winter Energy

(C) Second Block 2 – Non-Winter Energy

(ii) Rates for demand and energy in each block consistent with Hydro's proposed rates effective July 1, 2027.

IIC-NLH-007 **Application, Volume I, Section 6.7.6 Non-firm Rate; Application, Volume III, Exhibit 17, Christensen Associates Report, Section 2.3 Treatment of Non-firm load.**

At pages 6.24-6.25, Hydro states that industrial customer contracts currently include a provision for interruptible (non-firm) demand and that when customers are using interruptible demand, they are generally required to pay for their additional energy requirements based on the market value of exports. For non-firm service where thermal is the marginal source, Hydro is proposing to retain the previously approved calculation for the energy charge with an update to the loss factors.

Section 2.3 of the Christensen Report states under the current rate design a customer can adjust their power on order upward with some flexibility but downward only annually and that under the hours of use design customers will retain this demand management strategy but will have an additional incentive in that an increase in power on order will shift energy from Block 2 to Block 1.

(a) Please discuss if Hydro will permit customers to set their Power on Order, such that the value varies by season or by month under this revised rate design.

(b) If not, please explain why, considering that it would permit customers to better tailor the contracted service to their loads which may vary by month.

IIC-NLH-008 **Application, Volume I, Section 6.7.5 Island Industrial Customer Rate Impacts, Table 6-9 Customer Rate Impacts.**

Please provide versions of Table 6-9, showing monthly billings at existing rates and proposed rates, including riders, for customers with the following billing determinants and for all scenarios please assume the energy purchases are distributed evenly throughout the year (i.e. flat load profile):

(a) A customer who uses 70,000 MWh each year with a power on order of 10 MW (approximately 80% load factor)

(b) A customer who uses 70,000 MWh each year with a power on order of 9 MW (approximately 89% load factor)

(c) A customer who uses 70,000 MWh each year with a power on order of 11 MW (approximately 73% load factor)

(d) A customer who uses 61,000 MWh each year with a power on order of 10 MW (approximately 70% load factor)

(e) A customer who uses 61,000 MWh each year with a power on order of 9 MW (approximately 63% load factor)

(f) A customer who uses 61,000 MWh each year with a power on order of 11 MW (approximately 77% load factor)

Please provide all calculations in electronic form, with live calculations.

IIC-NLH-009 **Application, Volume I, Table 6-9 Island Industrial Customer Rate Impacts**

Please discuss, with assumptions documented and supporting quantified examples where possible, Hydro’s perspectives on the impacts of the proposed rate structure on a customer who chooses to electrify a heating or other process load currently served primarily by fossil fuels, in particular:

(a) In Hydro’s view, is the proposed rate structure intended to disincentive such electrification? If not, what rate options or other mitigations might be available to the customer to ensure electrification of such loads is not disincentivized.

(b) Please provide a quantitative analysis assuming a customer with an existing load based on a power on order of 20 MW at 80% load factor then added a load for new electrification of a 5 MW heating load at 50% load factor.

(c) Please describe what mix of options, including adjusting power on order, use of non-firm rate options, potential access to capacity assistance agreements and any other rate options might be available to manage bill impacts or achieve bill reductions.

IIC-NLH-010 **Application, Volume III, Exhibit 16, Attachment 1, NLH Effective Load Carrying Capability Study, Table 4.**

Hydro states it is expecting to enter into a capacity assistance program with MUN in 2026 for up to 21.7 MW across the year for 4 hours where the total number of calls cannot exceed 20 calls annually and notes the terms of the agreement have not been finalized.

(a) Can Hydro provide any updates on the timing or terms of capacity assistance agreement?

(b) Is MUN currently a customer of Hydro or Newfoundland Power? If Newfoundland Power, please explain why the capacity assistance program agreement would be with Hydro and not Newfoundland Power?

(c) Please confirm if the 21.7 MW relates to fuel switching to dual-fuel electric boilers. If not, please describe the nature of the 21.7 MW capacity assistance value.

(d) Please explain why Hydro proposes to limit the number of calls to 20 calls annually. In particular, if calling on the capacity assistance from MUN requires MUN to switch to back-up fuel systems, please explain why this action would need to be limited to 20 times per year.

(e) Has Hydro reflected the MUN capacity assistance program in its 2027 cost of service study? If so, please explain how it has been reflected. If not, please explain why not.

IIC-NLH-011 **Application, Volume III, Exhibit 16, Attachment 1, NLH Effective Load Carrying Capability Study, Table 4; Application Volume I, Section 6.2.3, Schedule F and Schedule G.**

Hydro describes the Generation Credit provided to Newfoundland Power in section 6.2.3 (both hydro and thermal) and states the existing calculation takes the total capacity of Newfoundland Power generation and subtracts a reserve at criteria to arrive at the generation credit. Hydro states the reserve at criteria is calculated by subtracting 240 MW from the total Island Interconnected System capacity at peak inclusive of capacity assistance contracts. Table 4 at page 32 of Attachment 1 describes the existing NP Capacity Assistance Program for up to 12 MW.

(a) Please provide a detailed explanation of how Hydro models the existing NP Capacity Assistance Program for up to 12MW in the cost of service studies in Schedules F and G of the application.

(b) Please provide versions of the cost of service studies in Schedules F and G assuming there was no 12 MW capacity assistance program with Newfoundland Power.

(c) Please provide versions of the cost of service studies in Schedules F and G of the application assuming there was no thermal generation credit to Newfoundland Power.

IIC-NLH-012 **Application, Volume I, Table 6-8; Schedule F 3.3A; Schedule 1, Attachment 3, Specifically Assigned Assets Report filed as part of Hydro's August 22, 2025 Application for Approval of Modifications to the Cost of Service Methodology**

(a) Please provide a version of Schedule F 3.3A that shows the derivation of the approved Industrial Customer Specifically Assigned Charges shown in Table 6-8 and describe any material changes as compared to the previous GRA to the proposed charges.

(b) Please provide a schedule itemizing the specifically assigned assets for each industrial customer in Schedule F3.3A, the in-service date of each asset, the net book value of each asset, and the calculations supporting the Depreciation, Return on Debt and Return on Equity for each specifically assigned asset.

(c) In Section 4.0 of Schedule 1, Attachment 3 from Hydro's August 22, 2025 Application for Approval of Modifications to the Cost of Service Methodology, Hydro stated that prior to its next GRA, Hydro intended to conduct a review of specifically assigned assets to assess whether assets currently designated as specifically assigned still meet the applicable criteria and whether any additional assets should be reclassified and that the results would be reflected in the next GRA.

Please provide a copy of the review of specifically assigned assets and:

(i) Describe how Hydro has incorporated the results of the review into the current GRA; and

(ii) Quantify the impacts of changes compared to the previously approved assets and methods for the specifically assigned charges for each industrial customer.

(d) In Section 3.0 of Schedule 1, Attachment 3 from Hydro's August 22, 2025 Application for Approval of Modifications to the Cost of Service Methodology, Hydro states historically it had generally recovered capital costs associated with specifically assigned assets through customer rates charged to that specific customer but that this methodology posed a risk of under-recovery if a customer ceases operation before the costs are fully recovered. Hydro stated it intends to continue the practice of recovering capital costs from industrial customers through direct charges upon project approval.

Please:

(i) Provide a schedule quantifying the amounts Hydro has recovered from each industrial customer through direct charges since this approach began; and,

(ii) Explain how this practice accords with the inclusion of depreciation and return in the calculation of specifically assigned charges for industrial customers.

IIC-NLH-013 **Application, Volume I, Table 3-1, Section 3.1 Operating Costs, p. 3.2**

Please provide a copy of Table 3-1 for each of before and after allocations to the General Expenses Capitalized Deferral Account.

IIC-NLH-014 **Application, Volume I, Table 3-2, Section 3.1.2 Operating Costs by Type, p. 3.5**

Please provide:

(a) the vacancy rate applied for/achieved for the 2019 GRA Test Year, and for each year from 2019 to 2024 Actuals; and

(b) the specific inputs used to calculate the vacancy rate (e.g. percentage of dollars, of positions, FTE versus employees, etc.).

IIC-NLH-015 **Application, Volume I, Section 4.2, Figure 4-1, p 4.4, regarding Hydro's Energy under the Muskrat Falls PPA**

(a) Please indicate the maximum quantities (or the rules used to calculate the maximum quantities) of supplemental energy available to Hydro if it had the Island load to use this power.

(b) Please provide the year-by-year actuals and forecasts of MF Energy, Base Block Energy, Deferred Energy and Supplemental Energy for 2024 to 2030..

(c) Please describe the potential for load growth on the Island Interconnected system to make use of added Base Block energy. Specifically:

(i) Will added use in every hour of the year be supplied by added Base Block energy consumption?

(ii) If not, what conditions will lead to added Island Interconnected load not being supplied from added Base Block energy (e.g., does it matter which month it occurs? Or system peaks at the time of consumption?). Please be specific about the conditions and likelihood that added load growth will come from other sources (e.g., added Holyrood or CT generation).

(d) Given supplemental energy is available for $1 in future years, please describe the circumstances in which Hydro would not monetize the entire deferred energy each year in light of its ability to source low cost supplemental energy in future years.

(e) Is it reasonable to conclude that Hydro's marginal generation cost for load growth that is supplied by Muskrat Falls supplemental energy is effectively $0? If not, please explain.

(f) Section 4.3.1 indicates the Base Block Capital Costs Recovery increased by $38.2 million from 2024 to 2027 due in part to "a higher volume of energy" being provided. Please provide the annual volumes of energy being referenced in this section for 2024 to 2027.

(g) Please provide a breakdown of the revenue from exports and how they are credited to Hydro regulated versus non-regulated operations.

(h) If deferred energy is exported, the GRA appears to note that Hydro regulated operations get the financial credit for this revenue. Is this the only source of export revenue to Hydro regulated and all remaining power exported is credited to Hydro's unregulated operations? If not, please explain.

IIC-NLH-016 **Application, Volume I, Section 5.2.1 Fuel Costs, p 5.3**

Hydro indicates that a substantial part of the increase in diesel and CT fuel quantities is due to the extended outage of Bay D'Espoir Units 5 and 6 due to the planned replacement of Penstock 3 in 2027.

(a) If the base rates for 2027 are based on this supply assumption, please indicate whether this test year is appropriate for application of the rates to 2028 or beyond, assuming Bay D'Espoir Units 5 and 6 are back in operation at that time?

(b) If Bay D'Espoir Units 5 and 6 are back on line in 2028, and this leads to volumetric savings in diesel compared to the test year assumptions (i.e., not related to drought or load changes), how would the impacts of this reduced diesel be accounted for (e.g., deferral account, Hydro's net income, etc.)?

IIC-NLH-017 **Application, Volume I, Section 5.2.3 Power Purchases**

Hydro notes that Exploits remains a power purchase transaction.

(a) Please provide any updates and plans in respect of RFI PUB-NLH-008 (Rev 1) from the 2013 NLH General Rate Application and the anticipated transfer in 2016, as per PUB-NLH-365 from that proceeding.

(b) Please indicate the pricing history for Exploits generation since the referenced 2013 GRA.

IIC-NLH-018 **Application, Volume I, Section 5.2.5 Depreciation and Accretion**

The GRA notes that the 2023 Depreciation Study and 2024 Technical Update result in a $7.3 million reduction in depreciation expense.

(a) Please provide separate estimates of the impact of the 2023 Study versus the 2024 Technical Update, with supporting calculations.

(b) Please specifically indicate the assumptions regarding Holyrood depreciation applied in the 2019 GRA, each actual year since the 2019 GRA, and in each of the 2024 Study and the 2024 Technical Update.

IIC-NLH-019 **Application, Volume I, Section 5.2.7 Rate Mitigation, Table 5-6, Rate Mitigation Funding**

(a) Please provide a detailed calculation showing the monthly revenues, organized by industrial/wholesale/retail, versus costs, and the resulting rate mitigation funding to achieve the values shown for 2025 Forecast, 2026 Forecast and 2027 Test Year.

(b) Is the $502 million for 2027 Test Year based on the assumed July 1 implementation of new rates, with the rate mitigation funding picking up the shortfalls from the first 6 months? If not, why not?

IIC-NLH-020 **Application, Volume I, Section 5.7.4 Demand Allocation of Long Term Supply Deferral Account**

The description of the demand allocator is "percentages derived from year-to-date kW for Utility Firm invoiced monthly billing demand, Industrial Firm maximum invoiced demand multiplied by the year-to-date months, and Rural Island Interconnected maximum peak demand multiplied by the year-to-date months".

The demand allocator in the Cost of Service is based on annual coincident peak demand, not invoiced monthly demand. Please indicate why the deferral account would not operate on the same basis?

IIC-NLH-021 **Application, Volume I, Section 5.7.5 Load Variation of Long Term Supply Deferral Account**

The load variation indicates that variations in export sales revenues arise due to changes in customer usage. Please confirm:

(a) This relationship only applies when loads are below the Base Block Energy, and not when loads are above the Base Block Energy when there is no effect on Hydro regulated export revenues. If not, please explain.

(b) There is no load variation deferral related to changes in demand revenues.

IIC-NLH-022 **Holyrood Fuel (Cost of Service Study and Long Term Supply Deferral Account) Application, Volume I, Schedule F, 2027 Test Year Cost of Service Study**

(a) Please provide a rationale for using annual energy to allocate Holyrood energy costs, if the Holyrood operation is only in winter. Please specifically and separately address:

(i) Holyrood fuel costs (as opposed to using monthly energy in the month in which the costs occur)

(ii) Holyrood energy-classified fixed costs (as opposed to using the sum of winter energy over the months where Holyrood operation is expected)

(b) Per Schedule F4.3, Application, Volume I, please provide calculations in support of the 455,225,658 kWh of forecast generation from Holyrood, indicating the specific derivation of this value and how the 70 MW minimum operating level is assumed as part of those inputs (i.e., is this value 70 MW times a given number of hours, etc.).

(c) Please provide a version of Schedule F based on the principle that Holyrood fuel is a necessary operating cost of securing Holyrood capacity, and is only incidental to producing energy, and is therefore classified the same as Holyrood capital costs (11.16% to energy, with the remainder to capacity).

IIC-NLH-023 **Application, Volume I, 2027 Test Year Cost of Service Study Schedule F4.2 System Load Factor**

(a) Please provide a detailed calculation of the Coincident Peak at Generation (kW) showing contribution by class, including which load and/or coincident factors were applied and where these are derived, and any adjustments made to the coincident peak (e.g., for generation credits, or capacity assistance credits).

IIC-NLH-024 **Application, Volume I, Section 6.7.6 Non-Firm Rate**

Hydro states that the Island Industrial Customer contracts currently include a provision for interruptible demand.

(a) Please provide an extract of the non-firm contractual provisions available to Industrial Customers, including maximum non-firm demand.

(b) Please provide the rationale for the non-firm maximum demand available as part of the Industrial Customer rate proposal. Please explain why the non-firm demand maximum is not set at a higher level than presently used.

(c) Please provide the actual non-firm monthly pricing (on and off – peak) since the initiation of the export-linked non-firm rate.

(i) Please indicate any hours or months in which Holyrood was considered the marginal source, and how much notice is provided to customers (if at all) that the pricing for non-firm energy has been adjusted to the cost of Holyrood generation.

IIC-NLH-025 **Application, Volume II, Exhibit 4, Load Forecast and Sources of Supply page 5.**

(a) At lines 10-12, it notes "[…] *This change in the UFLS scheme has greatly reduced constraints, and the capacity provided by the LIL can now fully support the Island Interconnected System load, less firm contractual commitments to Nova Scotia*". Please explain the meaning of "fully support" in the context of this sentence.

(b) Footnote 16 indicates: "*For clarity, the final UFLS scheme was not reflected in the 2027 Test Year as it was implemented after the production plan was developed*". Please provide:

(i) a comprehensive list of the 2027 GRA inputs, variables, assumptions, etc. that would change if the final UFLS scheme was known and reflected in the GRA.

(ii) an assessment of the direction of change of the estimate, and if possible, an indication of the magnitude of the change.

(c) Page 7 indicates: "*Since the commissioning of the LIL, the Holyrood TGS is not required to provide energy to the system during average hydrological conditions*." Please indicate if the PLEXOS runs supporting the GRA are based on this same conclusion, or whether this conclusion only arises after adoption of the final UFLS scheme, which was finalized after the GRA was prepared.

(d) Please update Slide 47 (Maritime Link-LIL Relationship) from Technical Conference #3 Resource Adequacy Plan dated October 16, 2024, based on the latest LIL capacity and UFLS assumptions.

(e) Please provide the latest Firm Energy Analysis to 2034 using the updated LIL capacity and UFLS assumptions (e.g. as an update to Slides 56-58 of the Technical Conference #3 Resource Adequacy Plan dated October 16, 2024) based on existing and committed resources. Please provide the same information for capacity.

DATED at St. John's, Newfoundland and Labrador, this 28th day of July, 2026.

POOLE ALTHOUSE

for Dana Constantine

Glen G. Seaborn

COX & PALMER

for Dana Constantine

Denis J. Fleming

STEWART MCKELVEY

Dana Constantine

Paul L. Coxworthy/Dana Constantine

TO: The Board of Commissioners of Public Utilities
Jacqui Glynn, Ryan Oake, Mike McNiven, Colleen Jones, Board Record, Michael Collins

TO: Newfoundland & Labrador Hydro
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