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July 29, 2026

Newfoundland and Labrador
Board of Commissioners of Public Utilities
120 Torbay Rd,
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 Labrador Interconnected Group

On behalf of the Labrador Interconnected Group, please find enclosed Requests for Information LAB-NLH-001 to LAB-NLH-033, dated July 29, 2026, in relation to the above-noted Application.

We trust this is satisfactory.

Yours truly,
Olthuis, Kleer, Townshend LLP
PER:

NICK KENNEDY
PARTNER

NK/sd

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

<u>Newfoundland Power Inc.</u>
Dominic Foley
Douglas Wright
Liam O'Brien
NP Regulatory

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

<u>Iron Ore Company of Canada</u>
Gregory A. C. Moores, Stewart McKelvey

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*"), as amended, 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

by the Labrador Interconnected Group

LAB-NLH-001 to LAB-NLH-033

July 29, 2026

Issue 1: Test Year Load Forecast

LAB-NLH-1 Re: 2026 GRA – Volume I, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027

Citation #1:

2026 GRA Volume 1, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027, p. 212 pdf

Page 1 of 1

Newfoundland and Labrador Hydro
Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027[1]
Labrador Interconnected System

	2019 Test Year		2019 Actual[2]		2020 Actual[2]		2021 Actual[2]		2022 Actual[2]		2023 Actual[2]		2024 Actual[2]		2025 Forecast[3]		2026 Forecast[4]		2027 Test Year[4]	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected	171.2	752.7	157.2	710.2	154.8	677.8	148.5	673.7	161.4	736.4	167.1	730.9	170.8	698.2	169.7	693.9	166.8	728.0	168.9	735.8
Department of National Defence[5]	-	-	-	0.1	-	0.1	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Customers																				
Iron Ore Company of Canada	240.0	1,740.6	250.7	1,658.3	245.4	1,659.9	245.3	1,589.7	238.9	1,618.2	246.5	1,461.3	255.3	1,547.8	248.5	1,554.4	262.0	1,575.4	262.0	1,575.4
Tacora Resources Inc.	53.0	285.4	50.5	160.0	53.4	343.0	53.7	312.4	58.0	342.4	51.1	336.8	54.8	316.4	55.1	310.9	55.0	327.0	55.0	327.0
Total Industrial Customers	293.0	2,026.0	301.1	1,818.3	298.8	2,002.9	299.0	1,902.2	297.0	1,960.6	297.7	1,798.0	310.1	1,864.1	303.6	1,865.3	317.0	1,902.4	317.0	1,902.4
Total Deliveries[6]	410.1	2,778.7	400.8	2,528.6	441.5	2,680.8	409.0	2,575.9	432.8	2,697.1	422.4	2,528.9	443.5	2,562.3	429.2	2,559.2	450.1	2,630.3	452.0	2,638.2
Transmission Losses[6]	34.2	191.9	31.5	165.5	33.9	180.5	30.0	163.5	11.6	158.8	15.3	134.3	5.9	155.9	11.8	134.7	27.6	181.8	28.2	171.9
Total Hydro Labrador Interconnected System Electricity Requirement	444.3	2,970.6	432.3	2,694.1	475.4	2,861.4	438.9	2,739.4	444.4	2,855.9	437.7	2,663.2	449.5	2,718.2	441.0	2,693.8	477.7	2,812.1	480.2	2,810.1

[1] Numbers may not add due to rounding.
[2] Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load.
[3] 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.
[4] The 2026 and 2027 Forecast is sourced to the June 2025 Labrador Operating Load Forecast.
[5] Sales to Canadian Forces Base Goose Bay are secondary sales.
[6] Demands for total deliveries and transmission losses are coincident with the system peak.

Footnote 3 reads "2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter."

Footnote 4 reads "The 2026 and 2027 Forecast is sourced to the June 2025 Labrador Operating Load Forecast".

Citation #2:

NLH Long-term Load Forecast Review – 2023, Table A-5

Table A-5: 2023 Planning Load Forecasts
Labrador Interconnected System Load Summary[12]

Reference Case	2023[13]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Labrador Requirements (GWh)	2,741	2,694	2,697	2,701	2,705	2,706	2,711	2,717	2,721	2,729	2,736	2,744
Growth Rate . . . (%)		-1.7	0.1	0.2	0.1	0.0	0.2	0.2	0.1	0.3	0.3	0.3
Labrador Customer Coincident Peak Demand (MW)	422	445	447	447	448	449	450	451	453	455	456	458
Growth Rate . . . (%)		5.3	0.4	0.1	0.2	0.2	0.2	0.3	0.5	0.4	0.4	0.4

Medium Growth Case	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Labrador Requirements (GWh)	2,816	2,772	2,778	2,790	2,829	2,875	3,081	4,155	4,539	4,637	4,700	4,758
Growth Rate . . . (%)		-1.6	0.2	0.4	1.4	1.6	7.2	34.8	9.2	2.2	1.4	1.2
Labrador Customer Coincident Peak Demand (MW)	422	446	447	450	451	467	467	651	707	721	731	740
Growth Rate . . . (%)		5.5	0.4	0.6	0.2	3.5	0.2	39.3	8.5	2.0	1.3	1.2

High Growth Case	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Labrador Requirements (GWh)	2,816	2,772	2,778	2,791	2,831	2,880	3,086	4,510	5,665	6,909	7,434	8,132
Growth Rate . . . (%)		-1.6	0.2	0.4	1.4	1.7	7.1	46.2	25.6	22.0	7.6	9.4
Labrador Customer Coincident Peak Demand (MW)	422	446	448	450	451	467	468	692	849	1,018	1,089	1,184
Growth Rate . . . (%)		5.5	0.4	0.6	0.2	3.5	0.2	48.0	22.6	19.9	7.0	8.7

Preamble:

We are unable to locate the June 2025 Labrador Operating Load Forecast referenced in Footnote 4. It does not appear to be part of the 2026 GRA.

We are unable to confirm whether these load forecasts in Citation #1 and Citation #2 are methodologically or structurally comparable.

The recent Supplemental Material to the GRA dated July 17, 2026, does not contain load forecast actuals for the entirety of 2025.

a) Please update Schedule A-II to include actuals for the entirety of 2025.

b) Please confirm that the 2023 Planning Load Forecast (Citation 2) is the most recent publicly available long term load forecast for the LIS prior to the 2026 GRA.

c) Please confirm that the 2023 Planning Load Forecast is a P50 forecast.

d) Please indicate if the reference forecast shown in Schedule A-II is a P50 or a P90 forecast.

e) Please provide in a format similar to Schedule A-II, the unsupplied P50 or P90 forecast for the LIS (including actuals for the entirety of 2025) to facilitate comparison with the 2023 Load Forecast and the June 2025 Labrador Operating Load Forecast.

f) Please file the June 2025 Labrador Operating Load Forecast for review in this proceeding.

g) Please explain any material differences in forecasting methodologies between the 2023 Load Forecast, the June 2025 Labrador Operating Load Forecast and the 2026 GRA load forecast for the LIS.

h) Please clarify whether Hydro prepared any alternative (e.g., "low", "high", etc.) forecasts to those provided in the 2026 GRA and provide these forecasts for the LIS and the IIS or explain why no alternative forecasts were prepared.

i) Please explain and justify the apparent substantial differences in the forecasted increased requirements of the IOC and the transmission losses (totaling more than 30 MW) between the 2023 Load Forecast and the 2026 GRA for the forecasted peak demand requirements on the LIS for the years 2026 and 2027.

LAB-NLH-2 Re: 2026 GRA – Volume I, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027

Citation:

2026 GRA Volume 1, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027, p. 212 pdf.

Preamble:

Historically, Labrador East and Labrador West have experienced different rates of load growth considering their different industrial, general service and residential customer bases.

Please provide separate tables similar to Schedule A-II for Labrador East and Labrador West for the years 2019 to 2027 in MW and GWh including both P50 and P90 load forecasts.

LAB-NLH-3 Re: 2026 GRA – Volume I, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027

Citation #1:

2026 GRA Volume 1, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027, p. 212 pdf.

Citation #2:

2026 GRA Volume 1, Schedule G various references to "CFB – Goose Bay Secondary", pp. 359, 368, 371, etc.

Citation #3:

2018 Capital Budget, Volume II – Tab 13

"Hydro projects the load for Upper Lake Melville area to grow from 79.8 MW in 2017 to 104 MW in 2042, including received service applications for new data centres, and a Department of Nation Defense conversion to electric boilers in 2020."

…

"The 7.6 MW increase in the 2017 forecast is a direct result of service applications for new data centres, while an increase of approximately 12.5 MW in 2020 is directly attributed to the Department of National Defense (DND) conversion to all-electric boilers."

Preamble:

The Department of National Defence is currently replacing the diesel-fueled boilers with electric boilers at 5 Wing Goose Bay ("heating electrification"). Construction commenced in May 2026 and is scheduled for completion in December 2030. (https://www.canada.ca/en/department-national-defence/news/2026/04/minister-thompson-announces-largest-defence-investment-in-newfoundland-and-labradors-history.html)

a) Please indicate the updated firm load (excluding secondary and interruptible load) attributable to heating electrification at 5 Wing Goose Bay.

b) Please present a load forecast for 5 Wing Goose Bay, broken down into firm, secondary and interruptible loads.

c) Please provide the operational definitions of secondary and interruptible loads.

d) Please indicate the date (month and year) that the Department of National Defence has most recently indicated to NLH that this heating electrification load will commence.

e) Please clarify to what extent (if any) the heating electrification will alter secondary energy sales to 5 Wing Goose Bay (i.e., "CFB – Goose Bay Secondary") compared to historical patterns, including whether this secondary energy demand will continue beyond the commencement of heating electrification.

LAB-NLH-4 Re: 2026 GRA – Volume I, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027

Citation #1:

2026 GRA Volume 1, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027, p. 212 pdf

Citation #2:

2018 Capital Budget, Volume II – Tab 13

"Hydro projects the load for Upper Lake Melville area to grow from 79.8 MW in 2017 to 104 MW in 2042, including received service applications for new data centres, and a Department of Nation Defense conversion to electric boilers in 2020." (p.i)

…

"The 7.6 MW increase in the 2017 forecast is a direct result of service applications for new data centres, while an increase of approximately 12.5 MW in 2020 is directly attributed to the Department of National Defense (DND) conversion to all-electric boilers." (p.5)

Preamble:

Since the time of the 2018 Capital Budget, the Government of Newfoundland and Labrador enacted Order in Council OC2022-266, November 10, 2022, removing the requirement of Hydro to provide firm service to data centres.

For each of Labrador East and Labrador West separately please:

a) indicate the number of data centre customers (all types, including cryptocurrency) currently receiving electricity service;

b) indicate whether all the data centre customers are cryptocurrency customers. If not, please describe the other types of data centres present in Labrador, and indicate the number and the forecast loads (firm, secondary and interruptible) for each;

c) confirm that the current firm load (excluding secondary and interruptible load) attributable to data centres is zero;

d) provide the historical and forecast monthly energy consumption of these data centres in the period 2019-2027, broken down into firm, secondary and interruptible loads;

e) provide the number of outstanding service requests for data centres, broken down into firm, secondary and interruptible loads; and

f) provide the combined load (MW) of those data centre service requests, broken down into firm, secondary and interruptible loads.

LAB-NLH-5 Re: 2026 GRA – Volume I, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027

Citation #1:

2026 GRA Volume 1, Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027, p. 212 pdf.

Citation #2:

P.U. 9 (2019)

The Board is satisfied that the information filed by Hydro shows that there are both reliability and capacity concerns in Labrador East, and that the Project is the least-cost alternative to address these concerns. The Board finds that the Project is reasonable and necessary to provide reliable service and meet load requirements and that it should be approved. The Board acknowledges that the costs of the Project are significant and that these costs may impact rates on the Labrador Interconnected system, both in Labrador West and Labrador East. Hydro estimated that the value of the capital assets to be placed into service in 2019 is $9.5 million, which would result in approximately $4.7 million in average rate base being recovered from customer rates. Hydro also noted that capital additions occurring subsequent to 2019 would not be recovered from customers until Hydro's next general rate application. The Board is satisfied that the concerns raised related to the impact on rate base and rates should be addressed in the context of the Board's processes associated with the approval of Hydro's ongoing and next general rate applications.

Preamble:

In 2019, NL Hydro received approval from the Board to construct the Muskrat Falls to Happy Valley Interconnection (P.U. 9 (2019)), which was projected to increase the transmission system transfer capacity to Labrador East from 77 MW to 104 MW.

a) Please confirm the date (month/year) that the Muskrat Falls to Happy Valley Interconnection began operating and entered the rate base.

b) Please confirm that the total transmission system transfer capacity to Labrador East is now 104 MW, or explain any deviations from this value.

c) Please provide the annual System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for the years since the Muskrat Falls to Happy Valley Interconnection became operational and five years prior to that date for:

i. Customers serviced by the Muskrat Falls to Happy Valley Interconnection (i.e., Labrador East);

ii. Labrador West; and

iii. the IIS.

LAB-NLH-6 **Re: 2026 GRA – 2026 GRA Volume 1, Table 1-1 Estimated July 1, 2027, Rates Increases by Customer Class**

Citation #1: 2026 GRA Volume 1, Table 1-1, p. 54 pdf

Table 1-1: Estimated July 1, 2027 Rates Increases by Customer Class (%)[41]

Customer Class	Estimated July 1, 2027 Rate Change Relative to 2026 Rates[42]
Utility[43]	3.3
Island Industrial[44]	(14.3)
Rural Labrador Interconnected[45]	2.25

Footnote 45 reads: "Labrador Interconnected System rates reflect the rate smoothing of 2.25% per year for four years."

Citation #2:

NLH Long-term Load Forecast Review – 2023, page vi

"The three Labrador Interconnected System forecast scenarios also project overall load growth for Labrador. The compound annual growth rate ranges from 0.1% in the Reference Case to 9.1% in the High Growth Scenario, highlighting the potential for significant load growth on that system stemming from **existing Industrial customers**." [emphasis added]

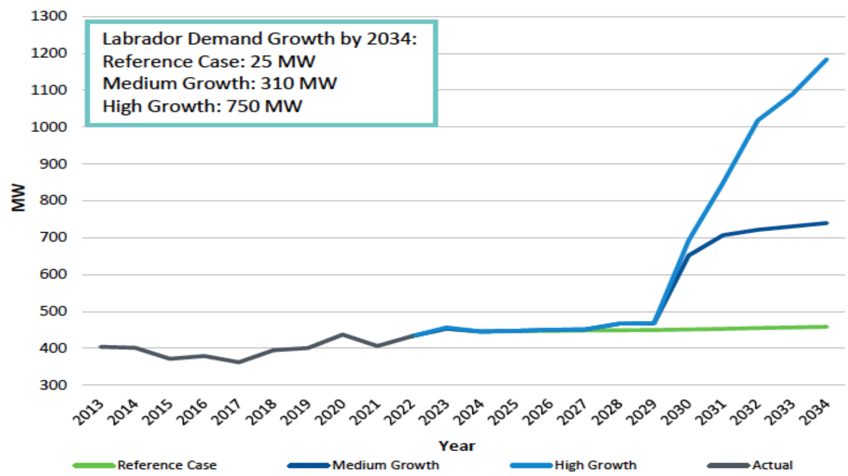

Chart 2: Labrador Interconnected System Annual Customer Coincident Demand Requirements[12,13]

Citation #3:

2026 GRA Volume 1, Schedule A-II, p. 212 pdf.

Schedule A-II: Actual and Forecast Electricity Requirements for 2019-2027 — Labrador Interconnected System
(Industrial Customers — IOC, Tacora, and Total, 2024-2027)

	2024 Actual[2]		2025 Forecast[3]		2026 Forecast[4]		2027 Test Year[4]	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Iron Ore Company of Canada	255.3	1,547.8	248.5	1,554.4	262.0	1,575.4	262.0	1,575.4
Tacora Resources Inc.	54.8	316.4	55.1	310.9	55.0	327.0	55.0	327.0
Total Industrial Customers	**310.1**	**1,864.1**	**303.6**	**1,865.3**	**317.0**	**1,902.4**	**317.0**	**1,902.4**

Preamble:

Table 1-1 in Volume 1 of the GRA indicates that Hydro proposes to smooth the rate increase in Labrador over the years 2027 through 2030 inclusive, and presumably any rate increases thereafter will be covered in a subsequent rate application. However, the 2023 Load Forecast for Labrador shows beginning in 2029 “the potential for significant load growth on that system [the LIS] stemming from existing Industrial customers.” If this magnitude and timing of load growth are still contemplated by Hydro, it is unclear what preparations are being made by NLH during the period covered by the current GRA (i.e. 2027-2030). Meeting a load growth of several hundred megawatts or more – whether through investments in new generation and transmission, recontracting of existing facilities, or some combination – would very likely entail significant rate increases for LIS customers.

The 2026 GRA LIS load forecast shows combined load growth for the Iron Ore Company of Canada and Tacora Resources of 6.9 MW and 38.3 GWh/year from 2024 to 2027.

a) Is the load growth of IOC and Tacora described in the Preamble from 2024 to 2027 their desired load growth, or the constrained growth resulting from limitations on the Labrador West transmission network and/or from the lack of sufficient energy and capacity on the LIS?

b) If it is the constrained load growth, would relieving these constraints result in substantially greater load growth?

c) Please provide updated tabular and graphical actuals and forecasts from 2015 to 2035 for reference, medium and high growth scenarios for the LIS in terms of i) annual customer coincident demand and ii) annual energy demand.

d) Please provide an update on any requests for additional power and energy from existing Industrial customers on the LIS, including the anticipated timing and magnitude of those requests.

e) Please provide an update on any requests for additional power and energy from new Industrial customers on the LIS, including the anticipated timing and magnitude of those requests.

f) Please describe the planning for additional generation and transmission currently being undertaken by NLH to meet the potentially increased demand forecast as early as 2029 for the LIS.

g) If the answer to any of the above is that this is not the proceeding in which this issue will be dealt with, please state, for that issue, in which proceeding will the issues be addressed by NLH and the Board?

LAB-NLH-7 Re: 2026 GRA – Volume III: Exhibit 16 Effective Load Carrying Capability Study

Citation #1:

2013 Amended GRA – Volume 1, page 4.15

"From a system planning perspective, Hydro no longer assumes that wind generation will be available to supply system capacity requirements. Therefore, Hydro is proposing that the purchased power costs related to wind be classified as 100% energy related. This proposal is reflected in the 2015 Test Year Cost of Service Study."

Citation #2:

2017 GRA LAB-NLH-61 Re: LAB-NLH-34

"e) Has Hydro explored the cost of service of installing wind generation to serve the winter peak in the Labrador Interconnected System? Why or why not? What have been the results of such exploration?"

[NLH Response:]

"e) Hydro has not explored the cost of installing wind generation to serve the winter peak in the Labrador Interconnected System because wind generation is not a technically viable alternative to provide reliable capacity during peak demand periods on the Labrador Interconnected System. The issue with capacity in Labrador is that the transmission system is nearing its limits during the winter months. In order to avoid transmission upgrades, generating capacity would have to be built at the load centres in Labrador East (Happy Valley-Goose Bay) or Labrador West (Labrador City/Wabush).

While wind may have some capacity value in areas where many wind farms can be constructed over a large geographic area and where there are strong transmission ties, this is not the case in Labrador. To avoid transmission upgrades, the wind farms would have to be built near the load centres. Over long time scales, i.e. years, wind production is very consistent. However, as wind has significant variability over short time periods, it cannot be depended on to be producing power at any particular time, especially given one or two wind farms in a small geographic area. As wind generation cannot be depended on to provide capacity at peak demand times, wind generation has not been considered as a technically viable option to serve the winter peak in the Labrador Interconnected System."

Citation #3:

2026 GRA – Volume 1: s. 6.3.1, page 183 pdf.

"The 2019 Settlement Agreement for Hydro's 2018 Cost of Service Methodology Review provided for the purchase cost of wind generation on the Island Interconnected System to be classified as 22% demand and 78% energy, based on Hydro's Effective Load Carrying Capability Study conducted by Hydro's resource planning group at the time. … The 2025 study found that the marginal Effective Load Carrying Capability for 50 MW of wind is 43% demand, an increase of approximately 20% from the previous 2018 study. …

"Hydro is therefore proposing to classify purchases of wind generation on the Island Interconnected System as 43% demand and 57% energy. This proposal is reflected in the 2027 Test Year Cost of Service Study."

Citation #4

2026 GRA Volume 1, page 77-78 pdf.

"By combining, or "pooling," generating sources and reservoirs, Hydro achieves the best opportunity to maximize the value of resources and maximize rate mitigation for customers. For instance, where appropriate and when there is excess available, Hydro will utilize Muskrat Falls energy to supply the Labrador Interconnected System and export the Recapture Energy, which would otherwise have been used to serve these customers. This approach enables additional Recapture Energy exports to external markets and maximizes the value of Hydro's hydrological resources for customers."

Preamble:

Over the past decade, Hydro's understanding of the capacity value of wind on the IIS has evolved from a 0% capacity contribution to a 43% capacity contribution. This suggests a higher capacity value to wind resources than modelled by Hydro in its prior submissions to the Board.

Since the 2017 GRA, the reliability of the LIS continues to improve due to prior and planned investments. Recent investments include the Labrador Transmission Assets, Labrador Island Transmission Link and the Muskrat Falls to Happy Valley Transmission Line. Hydro has also initiated the Labrador West Transmission Expansion Study (https://nlhydro.com/about-us/our-electricity-system/major-projects/labrador-west-transmission-expansion/), and additional 735 kV transmission is contemplated between Churchill Falls, a potential future Gull Island Project, and the Hydro-Québec system (https://www.ourchapter.ca/files/NewfoundlandLabrador-Quebec-MOU-English-Dec12-2024.pdf).

Like the Island, Labrador possesses high-quality wind resources and considerable wind development potential that could add value to existing or future hydroelectric resources with improvements to reliability, as well as the potential to reduce rates for existing Labrador customers or reduce increases in rates as load grows and the LIS expands.

a) Since the 2017 GRA, has Hydro has explored the cost of service of installing wind generation on the LIS? Why or why not? What have been the results of such exploration?

b) Since the 2017 GRA, has Hydro has explored the feasibility of installing wind generation as a complement to existing or future hydroelectric generation on the LIS? Why or why not? What have been the results of such exploration?

c) Please clarify when NLH plans to undertake an ELCC study for LIS like that recently prepared for the IIS.

d) Please indicate whether Hydro has explored the potential of developing wind resources on or near the Avalon Peninsula for the purposes of reducing reliance on energy and capacity provided by Muskrat Falls on the LIL?

e) If not in this proceeding, in which proceeding will these issues be addressed by NLH and the Board?

Issue 3: Test Year Supply And Supply-Cost Forecast

LAB-NLH-8 Re: 2026 GRA, Vol. I, Schedule A-V: Energy Supply and Fuel Expense for 2019–2027 Island Interconnected System

Citation #1:

2026 GRA Volume 1, Schedule A-V: Energy Supply and Fuel Expense for 2019–2027 Island Interconnected System, p. 215 pdf

Citation #2:

2026 GRA Volume 1, Schedule A-VI: Schedule A-VI: Energy Purchases by Suppliers for 2019–2027, p. 216 pdf.

Preamble

Materials provided for the IIS are not provided for the LIS.

Please provide for the Labrador Interconnected System:

a) an "Energy Supply and Fuel Expense for 2019-2027" table similar to that for the Island Interconnected System; and

b) an "Energy Purchases by Suppliers for 2019–2027" table similar to that for the Island Interconnected System.

LAB-NLH-9 Re: GRA, Vol. I, Table 3-5, page 122 pdf

Citation:

Table 3-5: Hydro's Operating Costs – Operations by Functional Area ($ Millions)[34]

Functional Area	2019 Test Year Restated[35]	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Transmission and Distribution	41.7	39.3	41.8	44.0	45.1
Production	43.7	40.9	42.1	43.5	44.6
Engineering Services	6.0	5.6	5.0	5.1	5.1
System Planning and NLSO	4.8	8.7	10.7	9.8	10.0
Major Projects and Asset Management[36]	0.6	2.3	2.0	2.4	2.5
Operating Technology	11.2	13.5	14.0	14.8	14.1
Total Operations Costs	**108.1**	**110.4**	**115.6**	**119.5**	**121.3**

Please provide a similar table for the Labrador Interconnected System only.

LAB-NLH-10 Re: GRA, Vol. I, page 75 pdf

Citation:

> When Muskrat Falls generation is more than sufficient to meet LIL deliveries to the Island, it can supplement the Labrador load requirement.[33]
>
> Note 33: As reported in Hydro's Supply Cost Variance Deferral Account Monthly Reports, Muskrat Falls and Hydro entered into a PPA for the purchase and sale of Residual Block Energy in February 2022. Under this agreement, Labrador Interconnected, Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, may now be serviced with energy from the Muskrat Falls Hydroelectric Generating Facility for the purpose of creating incremental Recapture Energy for export. The price paid by Hydro does not change as a result; therefore, customers are kept whole.

a) Please provide a copy of the PPA for the purchase and sale of Residual Block Energy.

b) Under this agreement, does Hydro purchase energy from Muskrat Falls at the price it pays for Recapture Energy from Churchill Falls?

   i. If yes, please explain the treatment of the revenues from exported Recapture Energy;

   ii. If not, please explain in detail the pricing of all elements of the transactions described in Note 33.

Issue 4: Labrador Interconnected Retail Rates
Issue 5: Labrador Industrial Customer Rates

LAB-NLH-11 Re 2026 GRA – Volume 1, Section 1.3.1 The Electricity System

Citation #1:

2026 GRA – Volume 1, Figure 1-1: Electricity System, p. 39 pdf

Figure 1-1: Electricity System

Citation #2:

2026 GRA – Volume 1, Section 1.3.1 The Electricity System, page 40 pdf

"On the Labrador Interconnected System, Hydro supplies customers in Labrador East and Labrador West with Recapture Energy and TwinCo Block Energy purchased from Churchill Falls. When Recapture Energy can be exported for the benefit of customers, domestic electricity demand is instead met using generation from Muskrat Falls. This approach enables additional Recapture Energy exports to external markets and maximizes the value of Hydro's hydrological resources for customers. Hydro also relies on the Happy Valley-Goose Bay GT, which is typically dispatched only when electricity demand or reserve requirements cannot be met."

Citation #3:

Rate Mitigation Options and Impacts, PUB-Nalcor-129, Attachment 1 (http://www.pub.nf.ca/applications/2018/2018ratemitigation/responses/PUB-Nalcor-129.pdf)

Preamble

Figure 1-1 is not consistent with the system maps typically filed by NLH in regulatory proceedings (e.g., in response to PUB-Nalcor-129 Rate Mitigation Options and Impacts Reference). It lacks important details respecting the LIS and IIS that are relevant to this proceeding and that have changed substantially since the previous 2017 GRA. The description in section 1.3.1 also lacks important details concerning changes to the LIS since the last GRA, and updated descriptions of the interconnectivity of the LIS for the purposes of understanding options for reliably serving the existing and future needs of the LIS and the IIS in a least-cost manner.

a) Please provide detailed, up-to-date and separate maps of the LIS and IIS networks, similar to those found in Citation 3, including the following:

   i. Geographical details, including municipalities, First Nations, waterbodies, etc.;

   ii. Transmission control regions (e.g., NLSO, NLH, NP, etc.);

   iii. All transmission lines, including voltages, type (AC/DC), asset identifications (e.g. L2304, etc.), ownership (NLH, LTC, NP, other) and operational status (e.g., if decommissioned or inoperable);

   iv. Interconnections with other provinces;

   v. Substations, including type (e.g., terminal, switching, electrodes, etc.), ownership and operational status; and

   vi. All remote and interconnected generating stations, including type, installed capacity, ownership

b) Please confirm that power from Churchill Falls is available at the Normand substation in Quebec.

c) Please describe the potential for power purchases from Hydro-Québec to meet Labrador West load growth.

LAB-NLH-12 Re: GRA, Vol. I, page 201 pdf

Citation:

6.8.3 Labrador Interconnected System

The average rate increase for rural Labrador Interconnected customers based on the 2027 Cost of Service Study is 8.54%. Government has advised that it supports a rate smoothing approach by Hydro to ease cost-of living pressures for customers. In particular Government supports the phase-in of the proposed rate increase for Rural Labrador Interconnected customers at an average increase per rate class of 2.25% per year over four years, with the first rate increase effective July 1, 2027 for all Hydro Rural classes on the Labrador Interconnected System with the exception of Street and Area Lighting. Hydro has outlined the proposed average customer rates calculated based on a 2.25% increase over four years starting in 2027 in Schedule E-III, with the first increase proposed herein to be implemented on July 1, 2027. Subsequent increases will be proposed annually for approval by the Board to be effective July 1 each year. At the end of the four years, Hydro is projecting a residual revenue deficiency of approximately $3.3 million and proposes that this residual revenue deficiency be addressed as part of Hydro's next GRA, or in a separate application at that time. Table 6-10 outlines the projected revenue deficiency in each year associated with the 2.25% phase in, along with the cumulative residual revenue deficiency at the end of the four years.

Table 6-10: Projected Revenue Deficiency – Labrador Rural Interconnected Phase In ($ Millions)

Year	Revenue Deficiency
2027	1.5
2028	1.1
2029	0.6
2030	0.1
Cumulative Revenue Deficiency	**3.3**

a) Is the rate increase of 8.54% based on the Cost of Service Study identical for each rate class? If so, please explain why. If not, please provide the increase for each class, with detailed calculations showing test year revenue requirement and projected revenues at current rates for each.

b) Please present the detailed calculations in support of the Revenue Deficiencies shown in Table 6-10, showing for each rate class: the billing determinants for each test year, revenues under existing and proposed rates, and the revenue deficiency.

LAB-NLH-13 Re: GRA, Vol. I, page 255 pdf

Citation:

Schedule F 1.2
Page 6 of 6

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit Allocation ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected						
1	Labrador Industrial Firm	9,171,998	9,172,200		-	9,172,200	1.00
2	Labrador Industrial Non-Firm	-	-		-	-	-
3	**Subtotal Industrial**	**9,171,998**	**9,172,200**	**-**	**-**	**9,172,200**	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
	Rural						
5	1.1 Domestic	106,057	206,448	-	22,577.87	229,025	0.46
6	1.1A Domestic All Electric	11,783,491	12,172,687	-	1,331,250	13,503,937	0.87
7	2.1 General Service 0-10 kW	302,008	302,668	-	33,101	335,769	0.90
8	2.2 General Service 10-100 kW	2,488,347	1,963,429	-	214,728	2,178,157	1.14
9	2.3 General Service 110-1,000 kVa	4,254,476	2,864,082	-	313,226	3,177,308	1.34
10	2.4 General Service Over 1,000 kVa	2,903,849	2,090,121	-	228,583	2,318,705	1.25
11	4.1 Street and Area Lighting	392,808	439,585	-	48,075	487,659	0.81
12	**Subtotal Rural**	**22,231,036**	**20,039,020**	**-**	**2,191,541**	**22,230,560**	
13	**Total Labrador Interconnected**	**31,403,034**	**29,211,220**	**-**	**2,191,541**	**31,402,760**	

a) Please confirm whether the "Revenues" column in Schedule F 1.2 (Page 6 of 6, column 2) reflects: (i) 2027 Test Year forecast billing determinants priced at rates in effect as of the date of filing; (ii) 2027 Test Year forecast billing determinants priced at the rates proposed in the GRA; or (iii) some other basis, identifying the specific rate schedule and effective date used.

b) Please provide "Revenues" by rate class reflecting 2027 Test Year forecast billing determinants priced at rates in effect as of the date of filing.

c) Please reconcile the requested average rate increase of 8.54% with the near identity between LIS revenues (col. 2) and revenue requirement after allocations (col. 6).

d) Please explain the large variation in revenue to cost coverage (column 7), ranging from 0.46 for “1.1 Domestic” up to 1.34 for “2.3 General Service”.

LAB-NLH-14 Re: GRA, Vol. I, page 205 pdf

Citation 1:

6.10.4 Rural Labrador Interconnected

The calculated increase in rates for Rural Labrador Interconnected customers is approximately 8.54%. Government has expressed its support for the phase-in of the rate increase at 2.25% per year, over four years, with the first increase implemented on July 1, 2027 for all rate classes except for Street and Area Lighting. The revenue deficiency with the projected rate increase of 8.54% on July 1, 2027 is approximately $1.7 million; the revenue deficiency complying with the Government request to phase in the rate increase is approximately $1.5 million.

Hydro is proposing a Rural Labrador Interconnected – Revenue Deficiency Deferral Account to record the revenue deficiency/sufficiency each month until the balance in the account is settled. The proposed deferral account definition is included within Exhibit 10.

Citation #2 (Vol. I, p. 201 pdf) :

Table 6-10: Projected Revenue Deficiency – Labrador Rural Interconnected Phase In ($ Millions)

Year	Revenue Deficiency
2027	1.5
2028	1.1
2029	0.6
2030	0.1
Cumulative Revenue Deficiency	**3.3**

a) Please confirm that the revenue deficiency of $1.5M with a smoothed rate increase mentioned in Citation 1 represents the revenue deficiency for the first year only, as seen in Citation 2.

b) Please confirm that the comparison to the $1.7M revenue deficiency with a single 8.54% rate increase in 2027 refers to the year 2027 only.

c) Whether or not this understanding is correct, please present year-by-year figures for both scenarios.

d) Please present a table showing the projected balance of the Rural Labrador Interconnected – Revenue Deficiency Deferral Account at the end of each year, including the financing costs as a separate line.

e) Please explain why Hydro thinks it is in the interest of Labrador consumers to defer these costs and pay interest on the deferral amounts.

LAB-NLH-15 Re: GRA, Vol. III, Exhibit 18, page 812 pdf

Citation:

As the calculated average rate increase for Labrador Interconnected customer rates is approximately 8.5 per cent, Government is writing to express support for a rate-smoothing approach of 2.25 per cent per year, for a period of four years to phase in the rate increase within your upcoming General Rate Application. This approach would reduce the impact of potential rate increases and help provide greater predictability for customers.

Preamble:

In the Citation, the Minister expresses support for a rate-smoothing approach but does not direct either Hydro or the PUB to accept it.

a) Please confirm the statement in the Preamble.

b) Please confirm that the letter from the Minister makes no mention of recovering any revenue deficiency resulting from the rate-smoothing approach.

c) Please comment on the proposal that any revenue deficiency that remains after the smoothed increase proposed by the Government be written off to net income.

Issue 11: Export Forecast, Export Revenues and Opportunity Cost

LAB-NLH-16 2026 GRA – Volume 1, Table 5-5, p. 150 pdf

Citation:

Table 5-5: Other Adjustments ($ Millions)[32]

	2019 Test Year	2027 Test Year
CIAC Revenue	(1.8)	(2.3)
Other Revenue[33]	(2.1)	(3.4)
Transmission Tariff Revenue	-	(18.3)
Net Export Revenue[34]	-	(40.2)
Capital Asset Cost of Service Exclusions[35]	(3.1)	(0.4)
Total Other Adjustments	**(7.0)**	**(64.7)**

Footnote 33 reads: "Other revenue consists of pole attachment and sundry revenue in the 2019 Test Year. In the 2027 Test Year, other revenue consists of pole attachment, greenhouse gas credit and sundry revenue. The province's Management of Greenhouse Gases Act came into effect on January 1, 2019, and provides for Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions. Under the Management of Greenhouse Gases Act, Hydro may sell these performance credits to certain other industrial facilities in the province. There were no forecast or actual sales of these credits in 2019; however, since that time, Hydro has completed sales of performance credits on an annual basis, and the revenue has been deferred in the Supply Cost Variance Deferral Account for the benefit of customers. Hydro is forecasting greenhouse gas credit sales in the 2027 Test Year of $1.3 million.

Preamble:

There is no differential treatment of greenhouse gas emissions credits regardless of the source of the generated electricity, including from Recapture Energy from CF(L)Co, Muskrat Falls or generation owned by NLH. All these sources of generation provide for Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions, which performance credits Hydro may sell to other industrial facilities in the province.

Please confirm or correct the statement in the preamble.

LAB-NLH-17 Re: GRA, Vol. I, pages 76-77 pdf

Citation:

Through mechanisms such as energy "banking" and "de-banking" under the Churchill River Water Management Agreement, Hydro can store energy that would otherwise be spilled and use, or export it, at a later time.[38] This optimizes resource utilization and can generate revenues that benefit customers by directly contributing to rate mitigation. For example, on behalf of Muskrat Falls, in recent years, Hydro sold energy banked in the Churchill Falls reservoir system out of province.[39]

Note 38: De-banking of this energy to meet demand is not forecast to occur during the 2027 Test Year, as the deliveries are considered non-firm.

Note 39: The delivery of additional blocks of energy was agreed to in 2023, with a total of 1.9 TWh delivered between 2024 and 2025.

Please clarify, in the cases referred to in Note 39, the accounting treatment of the resulting export revenues.

LAB-NLH-18 Re: GRA, Vol. I, pages 63-66 pdf

Citation:

2.2.2 Maximizing Value of Energy

Once the security of supply for domestic load is met, Hydro seeks to optimize the use of its hydrological resources. The role of Energy Marketing is to maximize value creation opportunities that arise due to the connection of the Island system with the broader North American grid. This is done through imports and exports. Export profits generated by Hydro are used to benefit customers either directly by offsetting Hydro's supply costs or through the funding of rate mitigation.

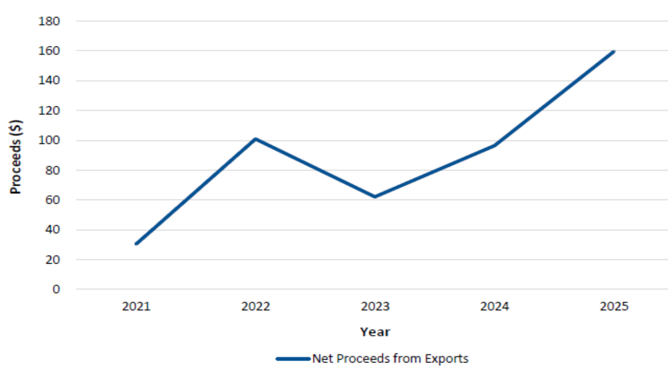

Chart 2-10: Value for Customers Generated by Energy Marketing ($ Millions)

a) Please present in tabular form the Energy Marketing costs (imports) and revenues (exports) resulting in the net proceeds shown in Citation 1, for each year from 2021 through 2025, inclusive;

b) Please explain the regulatory and accounting treatment of both import costs and export revenues.

c) Please explain, detail and quantify any benefits to LIS customers that result from Energy Marketing.

Issue 17: Operational Plans for the Muskrat Falls Assets

LAB-NLH-19 Re: GRA, Vol. I, page 76 pdf

Citation:

> The operation of the Churchill River system, which includes both the Churchill Falls and Muskrat Falls hydroelectric stations, is optimized through the use of daily coordinated production schedules for each facility. The hourly schedules ensure alignment with contractual commitments and system requirements.

a) Please explain in detail the coordination between the operators of the Churchill Falls and Muskrat Falls hydroelectric stations.

b) Is this a bilateral cooperation, or is the PUB or any other third party involved to ensure that operating schedules adequately reflect the interests of all parties?

Issue 18: Long-Term Supply Cost Variance Deferral Account

LAB-NLH-20 Re: GRA, Vol. I, page 165-166 pdf

Citation:

> The existing Supply Cost Variance Deferral Account accumulates costs, revenues and variances from the 2019 Test Year until the conclusion of Hydro's 2026 GRA; after that time, once a new test year is approved, Hydro proposes transitioning to the Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027. Hydro will propose the disposition of any balances remaining in the existing Supply Cost Variance Deferral Account after the transition to the Long-Term Supply Cost Variance Deferral Account in an application following the GRA.

a) Please present the details of the existing SCVDA, showing costs, revenues, variances from the 2019 and year-end balances from its creation to the present.

b) Please present the forecast evolution of the SCVDA from the present until the next GRA.

c) Please explain why Hydro thinks it is appropriate not to address the disposition of the SCVDA balances in the present GRA.

LAB-NLH-21 Re: GRA, Vol. I, page 168 pdf

Citation:

> **5.7.3 Energy Allocation**
>
> Each month, the energy costs will be allocated among the Island Interconnected customer groups of: (i) Newfoundland Power; (ii) Island Industrial Firm; and (iii) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for Utility Firm invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy. The portion of the energy costs which are initially allocated to Rural Island Interconnected will be re allocated between Newfoundland Power and regulated Labrador Interconnected System customers in the same proportion as the Rural Deficit is allocated in the most recently approved test year Cost of Service Study.
>
> The current month's activity for Newfoundland Power, Island Industrials, and regulated Labrador Interconnected System customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected System customers will be removed from the plan and, in between test years, written off to Hydro's net income (loss) consistent with past practice.

a) Please summarize the reasons why the Rural Deficit is in part allocated to LIS customers, and explain why and to what extent it considers that the same logic should be applied to the LTSCVDA.

b) Given that the LTSCVDA concerns costs associated with the Muskrat Falls Project, please explain why Hydro considers it appropriate to allocate part of the LTSCVDA to Labrador Interconnected System customers.

c) Please estimate the annual dollar magnitude of the LIS allocation of the LTSCVDA and its write-off under a range of plausible variance scenarios.

d) Please explain the ratemaking and accounting rationale for allocating a share of the LTSCVDA to LIS and then writing it off to net income, as opposed to not allocating it to LIS in the first place.

LAB-NLH-22 **Re: GRA, Vol. I, p. 165 pdf, and GRA, Vol. III, Exhibit 13, Illustrative Example of Cost Variance Allocation, page 716 pdf**

Citation 1:

> The Supply Cost Variance Deferral Account enables the deferral of costs related to Hydro's requirement to commence payment of Muskrat Falls Project costs[85] prior to recovering these costs.[86]
>
> Note 85: Muskrat Falls Project costs are comprised of payments made under: (i) the Muskrat Falls PPA and (ii) the Transmission Funding Agreement. The deferral account also captures rate mitigation funding and rate changes implemented solely to recover project costs to offset charges to Hydro. The deferral account enables Hydro to isolate the net effect of project costs and rate mitigation.
>
> Note 86: The Supply Cost Variance Deferral Account also includes variances for costs and revenues from Hydro's approved test year for items such as fuel costs associated with the Holyrood TGS, transmission tariff revenue, net revenues from exports, greenhouse gas credit revenues, load variations, rural rate adjustments, and other Island Interconnected System supply cost variances. The existing Supply Cost Variance Deferral Account definition reflects the calculation of financing charges based on Hydro's short-term borrowing costs.

Citation 2:

Long-Term Supply Cost Variance Deferral Account
Illustrative Example of Cost Variance Allocation
Energy Only Allocator vs Demand/Energy Allocators[1]

Cost Allocation

Component	Variance Allocations[2] Demand (%) [A]	Energy (%) [B]	Variances From Test Year[3] ($ Millions) [C]	Demand Allocation ($ Millions) [D] = [A] * [C]	Energy Allocation ($ Millions) [E] = [B] * [C]
Muskrat Falls Project Costs	50%	50%	5.5	2.8	2.8
Net Revenue from Exports	50%	50%	17.2	8.6	8.6
Transmission Tariff Revenue	50%	50%	(1.3)	(0.7)	(0.7)
Rate Mitigation Funding	50%	50%	38.0	19.0	19.0
Holyrood TGS	0%	100%	(3.4)	-	(3.4)
Utility Load	50%	50%	(6.8)	(3.4)	(3.4)
Industrial Load	50%	50%	(5.1)	(2.5)	(2.5)
Greenhouse Gas Credits Revenue	50%	50%	1.6	0.8	0.8
Other Island Interconnected System Supply Cost					
Thermal	100%	0%	0.2	0.2	-
Off-Island Purchases	50%	50%	-	-	-
On-Island Purchases	50%	50%	0.0	0.0	0.0
Wind Purchases	43%	57%	-	-	-
			45.8	**24.7**	**21.1**

a) Please confirm that the elements listed in footnote 86 (Citation 1) are all related to the Muskrat Falls Project costs. If not, please explain in detail.

b) Please confirm that, unlike the SCVDA it replaces, the LTSCVDA includes costs other than Muskrat Falls Project costs.

c) Of the cost components listed in the Citation 2, please indicate those that are in some way relevant to LIS customers, and explain their relevance.

d) Are there possible scenarios in which the LTSCVDA balance will be positive? If so, please describe such scenarios in detail.

e) In such scenarios, would the payment due to LIS customers under the proposed allocation rules be returned to them, or credited to net income?

LAB-NLH-23 Re: GRA, Vol. I, page 169 pdf

Citation:

5.7.5 Load Variation

The load variation in the Supply Cost Variance Deferral Account removes revenue variations from test year sales to Newfoundland Power and Hydro's Island Industrial Customers. While the allocation of the load variation is not an issue for the preparation of the cost of service, it is necessary to review, as Hydro is proposing to allocate variances in the Long-Term Supply Cost Variance Deferral Account based on demand and energy instead of the past practice of allocating supply and revenue variances based on energy only.

The load variation is calculated using the marginal cost of energy for Newfoundland Power and the average embedded cost of energy for Island Industrial Customers based on the test year. As load changes, customer revenue is impacted, but the export value in the deferral account also changes since it is the marginal cost of supply on the Island Interconnected System. As more energy is sold to Island Interconnected customers compared to the test year, less energy is available to export. The opposite is also true as customer load or sales decline, more energy is available to export. These variations in export sales are reflected in the Net Revenue from Exports component of the Supply Cost Variance Deferral Account.

Therefore, Hydro proposes to allocate the load variation in the Long-Term Supply Cost Variance Deferral Account between demand and energy using the system load factor, which is consistent with the allocation method approved for Net Revenue from Exports in Board Order No. P.U. 37(2019).

a) Please provide a numerical example of the Load Variation calculation described in Section 5.7.5, showing: (i) the marginal cost of energy used for Newfoundland Power; (ii) the average embedded cost of energy used for Island Industrial Customers; (iii) how each is derived from the 2027 Test Year; and (iv) the resulting dollar impact under an illustrative scenario where actual sales are, for example, 3% above and 3% below Test Year forecast sales.

b) Please confirm whether the marginal cost of energy used for the Load Variation calculation for Newfoundland Power will be updated periodically (e.g., annually, or upon Board-approved changes to the wholesale rate under Order No. P.U. 1(2025)), or held fixed at the 2027 Test Year value for the life of the LTSCVDA until the next GRA.

c) Please provide a precise definition of system load factor used to allocate the LTSCVDA. Is it based on the IIS, the LIS, or a combination of the two?

LAB-NLH-24 Re: GRA, Vol. I, page 170-171 pdf

Citation:

Hydro's proposal is for the Long-Term Supply Cost Variance Deferral Account to come into effect on January 1, 2027. This account will continue to capture variances between Hydro's incurred supply costs and those included in Hydro's most recently approved test year; however, these variances and the resulting balance in this account are expected to be much lower in comparison to those in the existing Supply Cost Variance Deferral Account as project costs and rate mitigation funding will be included in Hydro's cost of service and test year revenues, prior to this account becoming effective. Contrary to the existing Supply Cost Variance Deferral Account, when it was originally created, balances are not expected to be material and fast-growing, and this account will operate in a similar manner to Hydro's historical deferral accounts relating to supply costs, such as the Rate Stabilization Plan, where balances in the account are collected annually. For these reasons, this long-term approach to the Supply Cost Variance Deferral Account differs from the existing Supply Cost Variance Deferral Account at the time it was established; Hydro is proposing that the interest on the Long-Term Supply Cost Variance Deferral Account be calculated according to current regulatory practice in Newfoundland and

Labrador, using the weighted average cost of capital as approved in Hydro’s test year. The calculation of finance charges based on Hydro’s approved weighted average cost of capital has been included in the proposed account definition.

a) Please confirm whether the LTSCVDA is expected to routinely carry a debit or credit balance (or fluctuate materially between the two), and explain how the choice of interest rate (WACC vs. short-term borrowing) affects customers differently depending on the sign of the balance.

b) Please provide Hydro's best estimate of the projected LTSCVDA balance at the end of each year from 2027 through 2030, including the assumptions underlying the projection (e.g., assumed variance in Muskrat Falls PPA costs, export revenues, Holyrood fuel costs, and load).

c) Please confirm whether any portion of the LTSCVDA balance will be recovered from, or refunded to, customers on an interim or periodic basis prior to the next GRA, or whether the full balance will remain deferred until Hydro's next GRA in 2031.

d) If no interim recovery mechanism is proposed, please explain the ratemaking rationale for allowing balances (and associated financing charges) to accumulate over a four-year period without interim rate relief or refund, and discuss the customer rate-shock and intergenerational equity implications of that approach.

Issue 19: Other Deferral Accounts

LAB-NLH-25 Re: GRA, Vol. III, Exhibit 13, Electrification Cost Deferral Account Definition, page 683 pdf

Citation:

Electrification Cost Recovery

The Electrification Cost Recovery Adjustment, expressed in cents per kWh, will be calculated to provide for the recovery of costs charged annually to the Electrification Cost Deferral Account ("ECDA") over a ten-year period. The Electrification Cost Recovery Adjustment will be calculated to recover the sum of individual amounts representing 1/10th of the transfer to the ECDA for the previous year. There will be different Electrification Cost Recovery Adjustments for Island Industrial Customers and Newfoundland Power. The Electrification Cost Recovery Adjustment for Island Industrial Customers will be calculated based upon the Island Interconnected Recoverable Amount allocated for recovery from Island Industrial Customers. The ECDA Cost Recovery Adjustment for Newfoundland Power will be calculated based upon the allocated Island Interconnected Recoverable Amount to Newfoundland Power (including the allocated Island Interconnected Hydro Rural Amount) plus the allocated Hydro Rural Isolated System amount to Newfoundland Power.

Assignment of Customer Balance for Recovery

The Island Interconnected Recoverable Amount will be allocated among the Island Interconnected customer groups of (i) Newfoundland Power, (ii) Island Industrial Firm, and (iii) Rural Island Interconnected. The allocation will be based on percentages of previous calendar year sales for Utility Firm invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the Island Interconnected Recoverable Amount, which is initially allocated to Rural Island Interconnected, will be added to the Hydro Rural Isolated System Recoverable Amount, and then reallocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion in which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion of the Recoverable Amount which is re-allocated to Labrador Interconnected customers shall be charged to the ECDA for future recovery from customers on the Labrador Interconnected System.

a) Please provide a detailed account of the Electrification Cost Deferral Account (ECDA), showing all deferred amounts and their allocation each year from creation through the test year.

b) Please provide a forecast through 2031 of the Electrification Cost Deferral Account (ECDA), showing all deferred amounts and their allocation.

c) Please explain why Hydro thinks that LIS customers should contribute to the ECDA.

LAB-NLH-26 Re: GRA, Vol. III, page 693 pdf

Citation:

> **Rural Labrador Interconnected – Revenue Deficiency Deferral Account Definition**
>
> This account shall be charged on a monthly basis for the difference between (i) 2027 Test Year revenue calculated at Test Year Rates, and (ii) revenue at Current Rates, with both amounts determined using the 2027 Test Year load.

Please provide a detailed account of the **Rural Labrador Interconnected – Revenue Deficiency Deferral Account**, showing all deferred amounts and their allocation each year from creation through the test year.

LAB-NLH-27 Re: GRA, Vol. III, Exhibit 19, 2027 Revenue Deficiency Summary, page 814 pdf

Citation:

2027 Revenue Deficiency Summary
($000)

Customer Group	Jan. to June 2027 Revenue	July to Dec. 2027 Revenue	Total 2027 Test Year Revenue	2027 Test Year Costs	Deficiency / (Excess)	Recovery/Transfers: Supply Cost Variance Deferral Account	Recovery/Transfers: Frequency Converter	Recovery/Transfers: Return on Equity Deferral Account	Balance
	(A)	(B)	(C) = (A) + (B)	(D)	(E) = (D) - (C)	(F)	(G)	(H)	
IIC Demand & Energy	19,298	20,478	39,776	42,402	2,627				
IIC Specifically Assigned - Deferral	159	207	366	413	48				
IIC Total	**19,457**	**20,684**	**40,141**	**42,816**	**2,674**	**(2,674)**			-
Newfoundland Power	318,633	258,096	576,729	636,812	60,083	(60,083)			-
Labrador Interconnected	11,896	8,806	20,702	22,231	1,528		(98)	45	1,475
Government Rural[1]	1,470	1,203	2,673	2,824	151				151
Labrador Industrial	2,834	4,585	7,419	9,172	1,753		(26)	11	1,738
Total	**354,291**	**293,375**	**647,665**	**713,854**	**66,189**	**(62,757)**	**(124)**	**56**	**3,364**

[1] Includes recovery of deficiency starting July 1, 2027 in rates.

Please explain in detail the relationship between the figures shown for Labrador Interconnected in the 2027 Revenue Deficiency Summary and those for the Rural Labrador Interconnected – Revenue Deficiency Deferral Account.

Issue 27: Rural Reliability

LAB-NLH-28 Re: GRA, Vol. I, Charts 2-1 through 2-5, pages 63-66 pdf

Please present similar charts for the LIS.

Issue 28: Capital Planning

LAB-NLH-29 2026 GRA – Volume 1, Section 6.9.1 Rate Structure, p. 203 pdf

Citation

> "The average embedded cost for transmission demand allocated to Labrador Industrial customers has increased from $1.08 per kW per month for the 2019 Test Year to $2.00 per kW per month for the 2027 Test Year. The increase results from additional transmission investment over an eight-year period on the Labrador Interconnected System, reflected in the 2027 Test Year, compared to the 2019 Test Year, as well as an increase in cost allocated to this customer class due to increased load compared to the 2019 Test Year."

Please provide a detailed list of the transmission assets added to the Labrador Interconnected System rate base since 2019, with amounts and year of commissioning for each.

LAB-NLH-30 2026 GRA – Volume 1, s. 1.3.1, p.1.7

Citation #1:

> "On the Labrador Interconnected System, Hydro supplies customers in Labrador East and Labrador West with Recapture Energy and TwinCo Block Energy purchased from Churchill Falls."

Citation #2:

> Labrador Interconnected System Transmission Expansion Study (Revised April 3, 2019), s.4 System Deficiencies
>
> "The main focus of this report is to assess the system deficiencies driven by load growth on the LIS and develop least-cost, reliable transmission system expansion plans for ranges of loading conditions. The following system deficiencies were identified during this Expansion Study:
>
> - Transmission Line Transfer Limits to Labrador East;
> - Transmission Line Transfer Limits to Labrador West;
> - Transformation Capacity – Wabush Substation; and
> - Transmission Line Thermal Limits – 46 kV System."

Citation #3:

> Labrador Interconnected System Network Additions Policy, page 18 of 23
>
> "Hydro performs an annual assessment of the previous Transmission Expansion Plan for the LIS based on its current demand forecast. This assessment allows for the determination of the timing of transmission system additions and modifications necessary to ensure safe,

reliable, and economical long-term operation. On this basis, a new Transmission Expansion Plan is developed.

Hydro filed its initial Transmission Expansion Plan for the LIS on October 31, 2018."

Citation #4:

Restriction on Load Additions on the Labrador Interconnected System – Update (April 7, 2021)

"It is Hydro's position, at this time, that the load restrictions for both Labrador East and Labrador West should remain in place; however, Hydro believes some modification may be appropriate in the future under specific circumstances, as detailed within." (p.1)

Preamble:

Considerable time has elapsed since the identification of these deficiencies and submission by Hydro of its revisions to the first Transmission Expansion Study for the LIS. It appears that Hydro has not revised the Transmission Expansion Study for the LIS since April 3, 2019, and provided only a single update to the Board on April 7, 2021, respecting its annual assessments of that study.

a) Please provide, in relation to each of these four deficiencies described in the Transmission Expansion Study a description of the status of each deficiency, including the extent to which the deficiency has been addressed to date or will be addressed by funds for which the Board has already issued approvals.

b) Please provide a description of any new alternatives to address these deficiencies that were not considered in the Transmission Expansion Study and that are currently under consideration or being implemented by Hydro.

c) Please provide a description of any new system deficiencies on the LIS that have been identified since the Transmission Expansion Study, Hydro's plans to address these deficiencies, and any consideration of alternatives.

d) Please confirm that no Transmission Expansion Study for the LIS has been prepared by Hydro since that submitted to the Board on April 3, 2019. If not confirmed, please provide copies of all transmission expansion studies or plans for the LIS prepared since that date.

e) Please provide all annual assessments of the previous Transmission Expansion Study, or subsequent studies (if any). If an annual assessment has not been prepared and submitted to the Board the year prior to submission of the 2026 GRA, please explain why, and prepare and submit such an assessment.

f) If not in this proceeding, in which proceeding will these issues be addressed by NLH and the Board?

LAB-NLH-31 Re 2026 GRA – Volume 1, p. 40 pdf

Citation #1:

"On the Labrador Interconnected System, Hydro supplies customers in Labrador East and Labrador West with Recapture Energy and TwinCo Block Energy purchased from Churchill Falls."

Citation #2:

2017 GRA Revision 5 – Volume 1, Chapter 5

"Labrador West transmission is nearing its capacity limitations. The cost of providing new transmission to meet load growth on the Labrador Transmission System is high and can materially impact future customer rates." (p.5.35)

Citation #3:

Labrador Interconnected System Transmission Expansion Study – Appendix B: Transmission System Analysis Future Supply of Labrador West – Table 4

Table 4: Overview of CPW of Alternatives and Transfer Capacity

Alt.	Description	Forecast (MW)	Winter Firm Capacity (MW)	Non-Firm Capacity (MW)	Estimated Cost ($ million)	CPW ($ million)
1	Status Quo (without Tacora)	<350	252	350	1.43	1.21
2	Status Quo with Curtailment (Baseline)	383	252	350	1.82	11.62
3	Status Quo with Curtailment (Low Incremental)	434	252	350	1.82	51.42
4	WTS Upgrades (Baseline)	383	252	421	15.12	13.22
5	WTS Upgrades (Low Incremental)	434	252	454	31.66	27.60
6	230 kV Line from CF[14] to Wabush	434	434	527	251.24	202.53
7	230 kV Line from CF to FLK (230/46 kV)	434	434	528	272.82	221.21
8	315 kV Line from BLK to FLK (315/230 kV)	434	434	514	141.40	151.67
9	315 kV Line from BLK to FLK (315/230/46 kV)	434	434	502	146.99	154.56
10	315 kV Line from CF to FLK (315/230/46 kV)	434	434	574	335.86	282.34
11	315 kV Line from CF and BLK to FLK (315/230/46kV)	434	473	563	397.97	373.53
12	250 MW Monopole from BLK to FLK	434	453	585	347.90	326.58
13	250 MW BtB Converter at BLK – 230 kV Line from BLK to FLK	434	434	612	233.16	205.03
14	250 MW BtB Converter at BLK – 230 kV Line from BLK to WTS	434	434	603	216.70	190.93
15	200 MW Gas Turbine	434	482	573	589.20	634.50
16	230 kV Line to FLK (230/46 kV)	499	499	636	279.72	214.78
17	315 kV Line from BLK to FLK	499	499	600	153.15	148.09

Citation #4:

Labrador West Transmission Expansion Study (https://nlhydro.com/about-us/our-electricity-system/major-projects/labrador-west-transmission-expansion/)

"The first phase of this study identified a single 735 kV transmission line as the preferred solution which will allow for a maximum power transfer limit of approximately 1500 MW."

Preamble:

In the 2017 GRA, there was considerable discussion of transmission constraints on the Labrador West system, of their implications for system reliability and of the potential rate implications of system expansion to address these issues. Yet, there is no mention of these issues in the 2026 GRA.

Recently, Hydro initiated a new Labrador West Transmission Expansion Study for which the preferred alternative is a 735 kV from Churchill Falls to Labrador West, including a new Flora Lake substation. Though this asset would not enter the rate base prior to the 2027 test year, ongoing costs are being incurred by Hydro and will continue for several years. In the Transmission Expansion Study filed pursuant to the Network Additions Policy, none of the potential options to address these constraints involved transmission above 315 kV. The cost of a 735 kV line would be materially higher than any options previously considered in documents filed by Hydro before the Board. This raises concerns of a substantial rate shock for LIS customers in the not-too-distant future.

a) Please indicate which of the alternatives listed in Citation #3 are currently being explored, and in which proceedings NLH has filed relevant materials with the Board for its information, review or approval.

b) Please provide:

i. Current load forecasts for Labrador West (reference, low and high scenarios);

ii. updated descriptions of the current preferred alternatives for meeting medium-term and long-term growth in Labrador West;

iii. descriptions of the criteria used to evaluate these alternatives; and

iv. an explanation of how Hydro arrived at the proposed 735 kV Labrador West Transmission Expansion as the preferred alternative for meeting long-term growth in Labrador West.

c) Please confirm that NLH has not yet filed with the Board any materials for its information, review or approval pertaining to Hydro's preferred 735 kV transmission line for serving Labrador West.

d) Please indicate at what point in time Hydro anticipates filing with the Board any materials for its information, review or approval pertaining to Hydro's preferred 735 kV transmission line for serving Labrador West.

e) Please indicate whether any costs pertaining to Hydro's preferred 735 kV transmission line are entering deferral accounts previously approved by the Board in the prior GRA or in another proceeding before the Board.

f) If not in this proceeding, in which proceeding will these issues be addressed by NLH and the Board?

Issue 29: Other

LAB-NLH-32 Re: GRA, Vol. I, pages 63-66 pdf

Citation:

> Hydro's system has become increasingly complex since its last GRA, with the integration of the Muskrat Falls Assets and the interconnection to the North American grid through the Maritime Link. The NLSO is responsible for safely and reliably managing the provincial electricity system in real time. In operating the system, Hydro ensures that the security of supply for domestic load remains paramount and continually looks for opportunities to optimize system operations in ways that deliver reliable, least-cost electricity and cost savings for customers, while doing so in an environmentally responsible manner.

Please explain the ownership, operational structure and regulatory framework of the NLSO. More specifically:

a) Is the NLSO part of Hydro, or an independent entity;

b) Do the NLSO staff have any other roles or responsibilities within Hydro? If so, please provide details;

c) Is the NLSO regulated by the PUB? If so, please provide details as to its regulatory framework and reporting requirements. If not, what oversight exists regarding its operations?

d) Is the NLSO mandated to ensure equal and non-discriminatory treatment between Hydro and other actors in the NL energy system? If so, please provide references to the documents setting out that mandate.

e) What is the NLSO's role, if any, with respect to cost allocation for the use of transmission infrastructure? What oversight exists with respect to that role?

LAB-NLH-33 2026 GRA – Volume 1, Section 2.2.1 Dispatch of Least-Cost Electricity

Preamble:

> Despite the increasing complexity of the LIS since the last GRA, the Application does not detail the role of the NLSO in relation to transmission and generation assets within Labrador that are not wholly-owned by NLH but that are essential to optimizing the value of hydroelectric resources in Labrador for the benefit of ratepayers.

a) Does the NLSO now operate the transmission lines connecting Churchill Falls to the Hydro-Québec system, do those lines remain the operational responsibility of CF(L)Co in coordination with Hydro Québec, or is some other party responsible for their operation?

b) Please confirm the current frontier and interface between the control area managed by NLSO and that managed by Reliability Coordinator of Quebec, particularly with respect to the Churchill Falls Generating Station and the transmission lines connecting it to the Hydro-Québec grid.

c) Please provide an update on any ongoing or recent discussions with CF(L)Co and Hydro-Québec respecting operational control over the 735 kV lines from the Churchill Falls Generating Station to the Labrador/Québec border.

d) Please provide an update respecting any ongoing or recent discussions with Hydro-Québec respecting whether agreement has been reached regarding the general principles for load balancing in the Labrador Balancing Authority Area.

e) Please indicate whether an agreement has been reached between NLSO, CF(L)Co and Hydro-Québec concerning the matters mentioned above in this information request. If so, please file that agreement for the Board's information in this proceeding.

All of which is respectfully submitted this July 29, 2026

Nick Kennedy
For the Labrador Interconnected Group

TO: The Board of Commissioners of Public Utilities

Newfoundland and Labrador Hydro

Newfoundland Power Inc.

Consumer Advocate

Iron Ore Company of Canada

Island Industrial Customer Group