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December 21, 2018

The Board of Commissioners of Public Utilities
Ms. G. Cheryl Blundon, Board Secretary
Prince Charles Building
210 - 120 Torbay Road,
St. John's, NL, A1A 2G8

Re: NLH Capital Application (2018) – Labrador Interconnected Group RFIs LAB-NLH-035 to LAB-NLH-067

Please accept the enclosed Requests for Information, served on behalf of the Labrador Interconnected Group.

Should you have any questions, please be sure to contact me.

Respectfully,
Olthuis, Kleer, Townshend LLP
PER:

SENWUNG LUK
PARTNER

SL/tw

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving:
1) its 2018 capital budget pursuant to s.41(l) of the Act;
2) its 2018 capital purchases and construction projects in excess of $50,000 pursuant to s.41(3)(a) of the Act;
3) its leases in excess of $5,000 pursuant to s.41 (3)(b) of the Act;
4) its estimated contributions in aid of construction for 2018 pursuant to s.41 (5) of the Act.

IN THE MATTER OF Order No. P.U. 43(2017) in relation to Hydro's 2018 Capital Budget application; and

IN THE MATTER OF additional information filed by Newfoundland and Labrador Hydro pursuant to Order Nos. P.U. 43(2017) and P.U. 9(2018).

Requests for Information

by the Labrador Interconnected Group

LAB-NLH-35 to LAB-NLH-67

December 21, 2018

Requests for Information Regarding the Application for the Proposed Muskrat Falls to Happy Valley-Goose Bay Interconnection Project (the "Application")

Load forecasts

LAB-NLH-35 Re: Letter from NLH to Board dated November 30, 2018, Table 1; 2018 CBA, MFHVI Project, Revision 2, dated January 25, 2018, p. 13 of the pdf

Preamble :

> The Labrador East load forecast presented in the Transmission Expansion Study and reproduced as Table 1 is substantially lower than the load forecast presented as Table 1 on page 10 of the MFHVI project document produced as Tab 13 of the 2018 CBA. This forecast is identified in the Expansion Study as a P90 forecast, released in July 2018. Compared to the three forecasts shown in Appendix A of that same document (page 27 of the pdf), the current forecast is substantially higher than the Fall 2016 forecast, slightly higher than the Spring 2017 forecast, and substantially lower than the Summer 2017 forecast.

a) Are the three forecasts in the CBA also P90 forecasts? If not, please specify.

b) Please explain in detail the reasons behind these multiple changes in the Lab East load forecast, and explain in detail reasons for the reduction noted between the Summer 2017 load forecast and the July 2018 load forecast presented in Table 1 of the November 30 letter.

c) Has the load forecast been updated since July 2018? If so, please present the most recent Labrador East load forecast.

d) Please break down each of these forecasts, year by year, between i) loads related to cryptocurrency mining activities ("data centres"), ii) loads related to DND conversion to all-electric boilers and iii) other loads.

e) The 2018 Base Coincident Peak, according to Table 1 of the Nov. 30 letter, is 81.7 MW. Please indicate actual peak demand for the years 2016, 2017 and 2018, breaking them down into a) loads related to cryptocurrency mining activities ("data centres"), and b) other loads.

f) Please provide the most recent load forecast, under the hypothesis that all data centre loads are curtailed for the peak 300 hours.

LAB-NLH-36 Re: NLH, Attachment 1, Responses to PUB Questions, page 2

Citation:

> Table 1 provides actual peak demands for the Happy Valley-Goose Bay system since the winter of 2000/2001.

> The 2017/2018 peak of 66.9 MW (to February 28, 2018) is less than the forecast requirement of 79.9 MW primarily because the connected data centre customer loads have not ramped up to operational load requirements. In addition, the temperatures during system peak periods for the current winter to date have been milder than normal peak period weather conditions for this region.

Preamble:

> Table 1 shows peak loads of 71.1 MW in 2016/17 (the historic high), and of 66.9 MW in 2017-18p.

a) Please provide the actual peak load in the winter of 2017/18.

b) Please provide:

   i) the forecast peak load in the winter of 2018/19,

   ii) the forecast peak load in the winter of 2018/19 without the 5.5 MW interruptible contract with Labrador Lynx Ltd.,

   iii) the forecast peak load in the winter of 2018/19 without any data centre loads, and

   iv) the forecast peak load in the winter of 2018/19 under the hypothesis that all data centre loads are curtailed for the peak 300 hours of the year.

LAB-NLH-37. Re: Letter from NLH to Board dated November 30, 2018, page 3

Citation:

> The data shows that while transmission system capacity remains at 77 MW at the 25 kV bus in the Happy Valley Terminal Station, the current coincident peak load forecast is above the transmission system capacity.

a) Please confirm that, without taking into consideration the temporary 5.5 MW interruptible contract with Labrador Lynx Ltd., Hydro's existing customer base would have a coincident peak load forecast for winter 2018-2019 that is above the transmission system capacity of 77 MW.

b) Please explain how it came about that Hydro has accepted service requests with peak loads greater than the amounts it is capable of serving reliably with existing infrastructure.

c) Is it good utility practice to accept service requests resulting in peak loads greater than the amounts the utility is capable of serving reliably with existing infrastructure? Please provide references in support of your response.

LAB-NLH-38 Re: Labrador Expansion Study, p. 18-20 (pdf)

Citation:

> 3.1.1 Labrador East
>
> … Looking forward, the near-term load growth on the system is expected to be primarily driven by general service sales growth associated with recently approved data centre developments. Energy sales to the Department of National Defence's ("DND") large general service account amounts to roughly 30 percent of total general service sales on this system and is expected to remain stable. Potential exists for load increase associated with DND should it convert its central heating plant fuel from oil to electricity. For the longer term, forecasted load growth reflects a return to typical residential customer growth and modest expansion of the area's general service loads. (page 20) (underlining added)
>
> …
>
> 3.1.2 Labrador West
>
> … Looking forward, the near-term load growth within the region is primarily driven by general service sales growth associated with recently approved data centre developments. Based on expressed interest in data centre developments, the potential for increased general service electricity sales within this region is considered significant. (underlining added)

Preamble:

Table 3 provides a P90 peak load forecast (released in July 2018).

a) For both Labrador East and Labrador West, please break down this load forecast, year by year, distinguishing between data centre loads, industrial loads, and other loads.

b) Please provide an update regarding DND's intentions with respect to the possible conversion of its central heating plant from oil to electricity.

c) Has Hydro indicated to DND that it may not have sufficient capacity to supply electricity for this purpose during all hours of the year?

d) In the event that DND decides to proceed with its electric conversion, has Hydro asked DND to consider continuing to use its existing oil-burning boiler during certain hours?

e) For both Labrador East and Labrador West, please indicate each new customer with a peak load greater than 200 kW that has been added to the Lab West system since 2016, providing for each:

   i. The customer's name (or a unique indicator, if for privacy reasons the name cannot be revealed);

   ii. The location of the premises;

   iii. The date of the service request;

iv. The peak capacity requested;

v. The date when the service request was accepted;

vi. The date when service was initiated; and

vii. The total billings for each calendar year since service was initiated.

LAB-NLH-39. Re: Labrador Expansion Study, p. 21 (pdf), note 14

Citation:

> In the event Tacora operations do not materialize, the baseline load forecast will not exceed the 350 MW capacity of the existing transmission system. The resulting impacts of such a change in forecast are addressed in sections of this report relating to transmission system expansion plans.

Please provide the baseline peak load forecast for Labrador West, without the Tacora loads, distinguishing between data centre loads, industrial loads and other loads.

LAB-NLH-40 Re: Letter from NLH to Board dated November 30, 2018, pages 3-4, Table 4

Preamble :

> The table shows commissioning of « Transmission/Muskrat Falls TS2 Expansion » ending in December 2019, and commissioning of « Happy Valley Terminal Station upgrades/expansion » ending in October 2020.

Preamble:

> "Therefore, the transmission line extension and Muskrat Falls TS2 work is scheduled for completion by December 2019, and the Happy Valley work will continue into 2020 and be complete by December 2020." (p3)

a) Please break down the total project costs between « Transmission/Muskrat Falls TS2 Expansion » and « Happy Valley Terminal Station upgrades/expansion ».

b) Please confirm that « the Project » consists of both of these components, and so that the Project will not be fully commissioned until October 2020.

Preamble :

> According to s. 7(b) of the Labrador Settlement Agreement, the Parties agree to « Inclusion of the MF-HV Project in Hydro's closing rate base for the 2019 Test Year, if approved by the Board for construction to be completed in 2019 prior to Hydro's 2017 GRA Compliance filing ».

c) Please explain Hydro's understanding of the implications of this provision and, for greater clarity, indicate the rate base amounts related to the MF-HV Project at the end of 2019, 2020 and 2021, under the following hypotheses :

a. The Board approves the Project in or before February 2019;

b. Hydro's 2017 GRA Compliance Filing is filed in March and approved in April;

c. Construction of « Transmission/Muskrat Falls TS2 Expansion » is completed in 2019, and

d. Construction of « Happy Valley Terminal Station upgrades/expansion » is completed in 2020.

LAB-NLH-40. Re: LAB-NLH-021

Under these same hypotheses, please provide:

a) The increase in rate base due to these two components, for the years 2020, 2021, 2022 and 2023;

b) The resulting increase in Labrador revenue requirements for the years 2020, 2021, 2022 and 2023;

c) The annual revenues expected from existing data centre customers in each of the years 2020, 2021, 2022 and 2023;

d) The estimated rate increase for existing customers in each of the years 2020, 2021, 2022 and 2023, assuming no load growth other than data centres;

e) The estimated rate increase for existing customers in each of the years 2020, 2021, 2022 and 2023, assuming the load growth described in the load forecast in Table 1 of the Nov. 30 letter; and

f) The estimated rate increase for existing customers in each of the years 2020, 2021, 2022 and 2023, assuming the load growth described in the load forecast in Table 1 of the Nov. 30 letter but where data centre loads are all curtailed for the peak 300 hours of the year.

LAB-NLH-41. Re: Labrador Expansion Study, p. 42 (pdf)

Citation:

> 9 Customer Rate Impacts
>
> There is significant uncertainty with respect to specific customer rate impacts associated with the expansion of the transmission system in Labrador. As presented in Section 7, the size and timing of customer requests will have a significant impact on

expansion requirements. Further, the application of the Network Addition Policy has the potential to impact cost allocations to ensure fairness. It is only by performing a detailed system impact study in response to a specific customer request that such rate calculations can be performed.

For the purposes of this Expansion Study, Figure 6 has been provided as a basis for the generic calculation of forecast rate impacts for rural and industrial customers in Labrador as a function of the capital costs of a transmission system expansion.

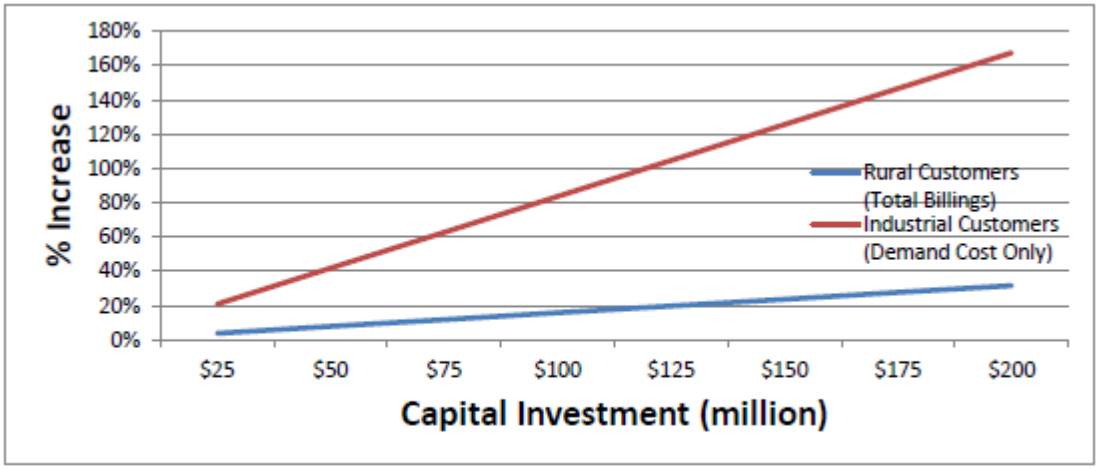

Figure 6: Projected Rate Increase vs. Capital Investment

Preamble:

Figure 6 suggests a linear relationship between capital investment and rate increases. However, given that the transmission expansion projects selected in the study are large and "lumpy", the relationship between load increases and rate impacts does not follow a straight line.

Please present graphs, separately for Labrador East and Labrador West, that indicate:

a) On the x-axis, peak load,

b) On the left y-axis, capital expenditures for transmission infrastructure required to meet the peak load on the x-axis, and

c) On the right y-axis, the % rate increase for rural and industrial customers resulting from those investments.

LAB-NLH-42. Re: LAB-NLH-006, page 6, Table 1

Preamble :

Table 1 shows that, in 2017, Labrador East load exceeded 70 MW for only 0.25 hours.

a) Please extend Table 1 to include 2018 (to date).

b) Please provide a version of Table 1 for 2017 and 2018 under the assumption that all "data centre" loads are curtailed during the 300 peak hours of the year.

LAB-NLH-43. Re: Labrador Expansion Study, pp. 26-27 (pdf)

Citation:

> A load flow analysis was performed to assess the network of 46 kV transmission lines that supply Hydro Rural customers in Labrador City and Wabush. …
>
> The results of the analysis indicate that transmission lines overloads exist in peak load conditions. To prevent the thermal overloading in the baseline forecast condition, the reconductoring of 46 kV transmission lines L32, L33, and L40 is required. The capital cost associated with this work is estimated to be approximately $1.4 million. This work will ensure sufficient capacity to meet peak load conditions for the 25-year study period.
>
> To prevent overload conditions in the sensitivity forecast condition, the reconductoring noted above, as well as that of L36, is required. The capital cost associated with this work is estimated to be approximately $1.8 million. This work will ensure sufficient capacity to meet peak load conditions for the 25- year study period.

a) Please indicate for how many hours per year these overload conditions are experienced.

b) Please indicate for how many hours per year these overload conditions would be experienced, if all existing and future data centre loads were curtailed during the peak 300 hours.

LAB-NLH-44. Re: LAB-NLH-021

Citation:

> Q. Please confirm that:
>
> a. the service requests that Hydro currently has for Labrador East exceed 32 MW including the 8.6 MW for which service contracts are in place.
>
> b. the service requests that Hydro currently has for Labrador East exceed the design capacity of the Muskrat Falls to Happy Valley Interconnection as applied for in the present proceeding.
>
> c. Hydro has received inquiries for 200 MW in Labrador East. …
>
> A. For item a, the 32 MW of service requests are in addition to the 8.6 MW already committed. Items b and c are confirmed.

Please update the information provided in LAB-NLH-021, indicating:

a) The total capacity of data centre customers in Lab East for which service contracts are in place,

b) The total capacity of pending requests for service in Lab East, distinguishing between data centres and other types of customers, and

c) The total capacity for which inquiries have been received for service in Lab East.

LAB-NLH-45. Re: PUB-NLH-050, page 1; Letter of Nov. 30, page 4

Citation:

> In order to maintain the possibility of completing the planned 2018 work, Hydro has commenced the engineering required to support the issuance of tenders for long lead equipment. At this point it is critical to advance the detailed design so that engineering can be completed and tenders for construction contracts prepared. These activities are critical to support a June construction start, which is essential given the short Labrador construction season. Hydro is in a position to award a contract to start the detailed design, and is awaiting Board approval in order to award that contract. Originally, Hydro's plan had detailed engineering beginning at the end of February. At this point, any further delay in starting this critical design element puts pressure on the completion date. If approval is granted around Friday, March 16, 2018, Hydro expects to achieve the in-service date of the interconnection, and the increase in capacity to Labrador East.

Preamble:

> Table 4 in the letter of Nov. 30 indicates that, with planning, design and procurement beginning in February 2019, the project could be commissioned by September 2020.

What is the latest date by which the PUB can approve the MFHVI in order to have construction of the MFHVI complete by December 2019? Please provide an explanation as to why this date was chosen.

LAB-NLH-46. Re: LAB-NLH-021

a) Has Hydro observed any reduction in power consumption by its data centre customers in the last six months? If so, please describe in detail.

b) Does Hydro have an idea of the bitcoin price threshold below which bitcoin mining in Labrador would not be cost effective? Please elaborate, and disclose any market studies within Hydro's possession on the elasticity of demand of data centre customers as it relates to the price of bitcoin.

c) Please disclose any forecasts of bitcoin prices that Hydro has in its possession.

d) Please state Hydro's view as to the factors behind the demand for electricity of data centre customers.

e) Please disclose any studies Hydro has done or has in its possession regarding the effects of cryptocurrency rates and policies in other jurisdictions (especially North American jurisdictions such as Quebec and New York State) on demand for electricity by cryptocurrency customers in Labrador.

f) Please disclose all data that Hydro has in its possession on electricity demand by data centre customers in 2017-18 in other jurisdictions.

g) Please disclose any forecasts that Hydro has in its possession of electricity demand by data centre customers in other jurisdictions.

Reliability

LAB-NLH-47. Re: Labrador East Reliability Plan, Monthly Status Report, December 17, 2018, page 2

Citation:

> **2.3 Inspections of L1301/L1302**
>
> Status: Ongoing
>
> Progress to Date: Ongoing
>
> Hydro has carried out infrared inspection of all line splices on L1301/L1302, with no defective splices discovered. Hydro has carried out several aerial patrols, most recently on November 5, 2018. No additional deficiencies were identified from the last aerial patrol. Patrols will continue at six-week intervals throughout the 2018-2019 winter season, with the next patrol scheduled for December 19, 2018.

a) Have any deficiencies been identified in L1301/L1302 since these regular inspections began? If so, please provide a list of all such deficiencies identified and the corrective measures that were taken.

b) Given these findings and the ongoing inspection protocol, please provide Hydro's best estimate of the probability of a major outage of the L1301/L1302 during winter 2018/19 and 2019/20.

c) Does Hydro own and operate any other radial transmission lines constructed in the 1970s or earlier? If so, please identify each one, and the refurbishments currently planned (if any), including estimated commissioning date and capital cost.

LAB-NLH-48. Re: Labrador Expansion Study, pages 220 and 223 (pdf); 2018 CBA, MFHVI Project, Revision 2, dated January 25, 2018, p. 34 of the pdf

Citation 1 (p. 220):

> Based on the current projection (solid red curve), the data used in this analysis indicates that the expected mean life for the L1301/L1302 wood pole plant asset is approximately 103 years (Figure 1), which is significantly higher than the conventional economic life of 40 years historically used in the industry. The typical Iowa curve assumes an expected asset life of 50 years. Similarly, the expected mean life for the X-arm shows that the asset life is 63 years (Figure 2).

Citation 2 (p. 223):

> **6 Recommendations for Replacement Rate and Initial Costs**
>
> Based on the asset life data analysis, it is estimated from Figure 3 that the replacement rate of the pole plant asset for L1301 for the next 20-year planning horizon would be 0.30 percent per year given that it has survived for 42 years of operation. Similarly, this replacement rate for the X-arm asset would be 2.3 percent per year (Figure 4).
>
> **7 Summary and Conclusions**
>
> Results of the data analysis clearly demonstrate that the expected life of the wood pole for L1301 is estimated as 103 years while the X-arm is estimated as 63 years. The line has survived 42 years of operations. The overall pole replacement rate per year is well below the published industry data. Based on the current rejection rate, it is estimated that Hydro may be required to replace 0.30 percent of pole plant asset per year for the planning horizon considered in this study. For the X-arm, this replacement rate would be 2.3 percent per year. Planned maintenance outage duration for L1301 is estimated to be seven days in each year of future operation to support this replacement rate and the number of poles and X-arms that need to be replaced per year. The planned maintenance outage duration should be pro-rated for L1302 in terms of line length.

Given these results, and assuming that the proposed maintenance program is followed, is there any reason to believe that there is a substantial risk of a prolonged forced outage on L1301/L1302? Please explain your answer.

LAB-NLH-49. Re: Labrador Expansion Study, p. 12 (pdf), note 3

Citation:

> As the L1301 transmission line was planned as a temporary installation, the towers between Churchill Falls and Gull Island were not designed to Hydro standards. Rather, phase spacing was shortened to 3.2 m as opposed to the standard value of 4.3 m.

Please explain the significance or consequences, if any, of phase spacing of 3.2 m instead of 4.3 m.

LAB-NLH-50. Re: 2018 CBA, MFHVI Project, Revision 2 (2018-01-25), pages 34-35 (pdf)

Citation 1 (page 14 of pdf):

> Five power supply options for the Upper Lake Melville area were analyzed from both a technical and cost benefit point of view. It was shown that while maintaining long term supply from Churchill Falls (status quo) with an additional 125 MVA transformer added at Churchill Falls, a 67 MVAR capacitor bank, and 50MVA transformer at Happy Valley – Goose Bay, had the lowest initial capital cost, it did not have the lowest cumulative net present value. Connection of the Upper Lake Melville to Muskrat Falls via construction of a six km long transmission line from the existing 138 kV right of way to the Muskrat Falls site had the lowest cumulative net present value of the five options.

Preamble:

i. The capital cost for Option 1 (125 MVA transformer at CF, 65 MVA Capacitor Bank, new 50 MVA transformer at HV) is given as $4.05 + $5.0 + $3.8 = $12.85 million. O&M costs are given as $450k/yr. The study assumed an annual one-week maintenance outage of L1301/L1302 for cross-arm replacement, requiring operation of the HV Gas Turbine, at a cost of $1.33 M/yr. (pages 34-35 of pdf) The analysis shows that, during that one-week maintenance outage, HV (including data centre loads) would occasionally exceed the 25 MW limit of the HVGT.

ii. Option 2 (the MFHVI project) shows a capital cost of $20.0 M, and O&M of $470k/yr. A maintenance outage is required for cross-arm replacement for L1302 only, and the HVGT usage estimate is prorated based on line length and estimated at $165.8k/yr. Loss savings are estimated at $1 M/yr (p. 38 pdf).

iii. Cumulative NPV is estimated at $33,478,915 for Option 1, and at $23,577,661 for Option 2. (page 54 of pdf)

a) Please provide detailed calculations showing the derivation of the NPV figures mentioned in Preamble iii), with references and sources for all data and assumptions used.

b) Please indicate the reduction in NPV for Option 1 that would result if data centre customers were curtailed during the maintenance outage, reducing fuel costs.

c) Is it possible to reduce the duration of the maintenance outage for cross-arm replacement by committing a large workforce to the task? If so, please indicate the increase in labour cost, and decrease in HVGT operating costs, that would result. If not, please explain why not.

LAB-NLH-51. Re: 2018 CBA, MFHVI Project, Revision 2 (2018-01-25), pages 54-58 (pdf); PUB-NLH-049, page 8 of 10

Citation (PUB-NLH-049):

> Recall that Option One is the status quo option in which incremental transfer over the existing 269 km long line to Churchill Falls is met by adding a second transformer at Churchill Falls and 138 kV shunt capacitors at Happy Valley. In essence, the calculations provide the unavailability and expected unserved energy for the existing system at 0.0046 and 1747 MWh, respectively.

Preamble :

> Section 9 provides a reliability analysis of the options studied, resulting in a calculated unavailability value (U) and expected unserved energy (MWh) for each one, as seen in Table 5 (p. 58 of the pdf).

a) Please confirm that the calculated unavailability and expected unserved energy of the current configuration (status quo) is the same as that given for Option 1.

b) For the current configuration and for Options 1 and 2, please express the calculated unavailability in hours/year.

LAB-NLH-52. Re: Labrador Expansion Study, p. 35 (pdf); 2018 CBA, MFHVI Project, Revision 2 (2018-01-25), pages 47, 50 and 54 (pdf)

Preamble:

> In the Labrador Transmission Expansion Study, Table 7 compares the CPV of the MFHVY interconnection (Alternative 2) to that of "Offload L1301/L1302" (Alternative 1), and shows a difference of $30.9 million.
>
> In the MFHVI Project, Revision 2, Option 2 (the MFHVI project) is compared to Option 1, which includes additional transformers and a capacitor bank, with a CPV difference of $9.9 million.

a) Please explain in detail the difference between "Alternative 1" in the Labrador Transmission Expansion Study and "Option 1" in the MFHVI Project documentation.

b) Please explain why the CPV difference is so much larger in the Labrador Transmission Expansion Study than it is in the MFHVI Project documentation.

LAB-NLH-53. Re: Labrador Expansion Study, p. 35 (pdf)

Citation:

> Marginal Cost of Energy: 3.5 cents per kWh.
>
> Footnote 26: Nalcor exports surplus energy to the North American grid at a historical profit margin of approximately 3.5 cents per kWh.

a) Please confirm that, once the LIL is in operation, the marginal cost of energy for Hydro in Labrador will be equal to the marginal cost of generation at Holyrood, rather than the historical profit margin for sale to the North American grid. If not confirmed, please explain why.

b) Please detail the implications for the analysis of using the marginal cost of generation at Holyrood as the marginal cost of generation.

LAB-NLH-54. Re: NLH, Attachment 1, Responses to PUB Questions, page 5

Preamble:

> In response to question 5 of the PUB, Hydro provided an estimate of $11M over a two-year lease for the use of mobile diesel units to accommodate the forecast 2019 peak load of 81.4 MW, including 5 units in 2018 and 6 units in 2019.

a) Please estimate the number of diesel units currently forecast to be required to meet 2018/2019 peak loads, and provide a cost estimate breakdown specifying:

i. rental cost;

ii. transportation and installation cost;

iii. fuel cost; and

iv. any other costs.

For fuel costs, please specify:

v. estimated generation;

vi. estimated fuel required; and

vii. estimated unit fuel cost.

b) Please provide a similar estimate for 2018/2019 peak loads, under the assumption that all data centre loads are curtailed for the peak 300 hours of the year.

LAB-NLH-55. Re: Labrador Expansion Study, p. 11 (pdf)

There appears to be text missing at the end of page 3 of the Study (p. 11 of the pdf). Please complete.

LAB-NLH-56. Re: Labrador Expansion Study, p. 14 (pdf); Labrador East Reliability Plan Board Update, 2018-12-17

Citation 1 (Labrador Expansion Study):

> At the North Side Diesel Plant ("NSP"), there is approximately 4 MW of diesel generation; however, due to the deteriorating condition of the plant, it is not reliable as a long term source of capacity.

Citation 2 (Labrador East Reliability Plan Update):

> 2.1 Ensure Reliability of the North Plant for Peak Loading Conditions
>
> Status: Closed
>
> Progress to Date: A third-party service provider for the North Plant Diesels carried out an on site assessment on April 26, 2018. The assessment indicated that the units were not in a condition to guarantee reliable service for the 2018-2019 winter season. Hydro does not anticipate seeking Board approval for capital work related to the North Plant.

Preamble:

> Citation 1 indicates that the NSP is not reliable as a long term source of capacity, and Citation 2 indicates that it is not in a condition to guarantee reliable service for the 2018-2019 winter season.

a) What is Hydro's conclusion regarding the NSP's current status? Is it functional? Can it be operated?

b) What are Hydro's intentions regarding the NSP? Does it intend to decommission it?

c) Please provide a summary of the costs that would be required to make the NSP functional i) for the short term, and ii) for the long term.

LAB-NLH-57. Re: Labrador Expansion Study, p. 14 (pdf)

When is IOC's synchronous condenser (SC3) expected to be commissioned? Is its commissioning conditional on other events? Please explain.

LAB-NLH-58. Re: Labrador Expansion Study, p. 38 (pdf); Network Addition Policy, page 8 (pdf)

Citation 1 (Expansion Study):

Table 10: Labrador East – Proposed Future Phases

Phase	Load Trigger (MW)[30]	Project Description	Cost Estimate ($ million)[31]
1	>77	MF to HVY Interconnection	20
2	>104	Transformation Upgrade at HVYTS[32]	5
3	>125	Transformation Upgrade at HVYTS and MFATS2[33]	15
4	>162	Construction of Second Line from MF to HVY	50

Citation 2 (Network Addition Policy)

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

a) Please confirm that the three expansion projects identified for Labrador East in the Network Addition Policy are identical to the projects identified as Phase 2, 3 and 4 in the table from the Transmission Expansion Study.

b) Please explain why the Phase 1 project from the Transmission Expansion Study (the MF to HVY Interconnection) was not included in the derivation of expansion costs in the Network Addition Policy.

LAB-NLH-59. Re: Network Addition Policy, page 8 (pdf)

Citation 1:

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

a) Please explain by what process Hydro decided which projects to include in the derivation of expansion costs.

b) Please explain why the MFHVI project is not included in the derivation of expansion costs.

c) Please explain why the additional expansion projects planned for Labrador West are not included in the derivation of expansion costs.

LAB-NLH-60. Re: Network Addition Policy, page 19 (pdf)

Citation:

> **Transmission Expansion Plan** refers to the most recent transmission system expansion plan for the Labrador Interconnected System filed with the Board. The Transmission Expansion Plan identifies Transmission Upgrades required to serve various load growth scenarios and the estimated costs to implement each upgrade.

Please identify which specific elements of the Labrador Transmission Expansion Plan filed with the Board on November 5, 2018 constitute the "Transmission Expansion Plan" for purposes of the Network Addition Policy.

LAB-NLH-61. Re: Labrador Expansion Study, p. 31-32 (pdf); Network Addition Policy, page 8 (pdf)

Citation 1 (Expansion Study):

> 5.2 Long-Term Supply to Labrador West
>
> 5.2.1 Transmission System Capacity Upgrades
>
> The analysis provided in Appendix B includes a description of the system additions that would be required to increase transmission system capacity in western Labrador to meet the peak baseline forecast of 383 MW.

The upgrades include the commissioning of the third synchronous condenser at Wabush Terminal Station,[23] the installation of an additional 23 MVAR of shunt compensation, and replacement of transformers T4 and T5 with 125 MVA units. These upgrade will increase system capacity to meet the baseline peak load forecast of 383 MW.

The estimated capital cost of this project is approximated 1 to be $15.0 million.[24]

Citation 2 (Transmission Expansion Study, page 39 pdf)

7.2 Labrador West

The existing 230 kV transmission system has a non-firm winter capacity of 350 MW and is adequate only if supply to industrial customers is restricted. System additions that would be required to meet the unrestricted baseline load forecast of 383 MW are described in 5.2.1. Hydro has conducted further analysis to determine the least-cost options incremental loading scenarios given a significant potential for incremental load in Labrador West. This comprehensive analysis is provided in Appendix B. Table 11provides a summary of the preferred alternatives.

Table 11: Preferred Alternative for Incremental Lab West Load Levels

Lab West Load (MW)	Least-Cost Option	Description of Alternative	Capital Cost ($ million)
> 383	Alternative 5	• Commissioning of SC3 • Replacement of T4, T5, and T6 with 125 MVA units for loss of largest transformer • Replacement of four, 46 kV circuit breakers due to exceeding fault level • Installation of 72 MVARs of reactive compensation (needed for loss of SC#3) • Thermal Upgrade of L23/L24 to 75°C conductor temperature	31.66
> 434	Alternative 17	• Construction of 50 km of 315 kV transmission line from Bloom Lake, ("BLK") to Flora Lake ("FLK") and 5 km of 230 kV from FLK to WAB. • BLK 315 kV and WAB 230 kV Line Terminations • Construction of new 315/230/46 kV terminal station at FLK • Installation of four 40.2 MVAR capacitor banks on FLK 230 kV Bus • Commission synchronous condenser SC3 • Upgrade of 14, 46 kV breakers with 2000 A, 31.5 kA breakers • 25 km of new 46 kV distribution lines plus upgrades to existing distribution lines	153.15

Citation 3 (Network Addition Policy)

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

a) Please confirm that the single expansion project identified for Labrador West in the Network Addition Policy (Citation 3) is identical to the one identified in the citation from the Transmission Expansion Study (Citation 1).

b) Please explain why the two projects identified in Table 11 of the Transmission Expansion Study, required if Lab West loads increase beyond 383 MW, were not included in the derivation of expansion costs in the Network Addition Policy.

c) Please provide an update for the status of the Labrador West Transmission Project (LWTP), a $330 M, 220-km transmission line between Churchill Falls and Labrador West, and explain why this project is not included in the options reviewed in the Labrador Transmission Expansion Study.

d) Is Option 17, described on p. 76 as "a new 315 kV line from Bloom Lake to Flora Lake with 46 kV Connection from Flora Lake", at a cost of $153 M, a replacement for the LWTP? Please explain.

LAB-NLH-62. Re: Labrador Expansion Study, p. 40 (pdf)

Citation :

> 7.2.1 Considerations for an Interconnection to Hydro-Québec
>
> As per Table 11, if incremental loads are such that forecasted loads in Labrador West exceed 434 MW, the least-cost alternative will involve an interconnection with Hydro-Québec at its Bloom Lake ("BLK") Station.
>
> Hydro has been in consultation with Hydro-Québec TransÉnergie ("HQT") with respect to interprovincial interconnection alternatives. These discussions have included cooperative transmission planning activities and have allowed for a shared understanding of commercial processes if such an interconnection were to be pursued.
>
> From a transmission planning perspective, a preliminary load flow study has been performed cooperatively by personnel from both utilities. The outcome of this

> analysis is that HQT has validated Hydro's load flow models and analysis and has provided preliminary confirmation of the technical viability of the interconnection.
>
> From a commercial standpoint, personnel from HQT have informed Hydro that if the interconnection is to be pursued, a Transmission Service Request will need to be submitted.[34] This request will be for a point-to-point service to a new delivery point to be established at the border in western Labrador. This request will trigger the system impact study process.

a) Please explain Hydro's power supply assumptions with respect to the Hydro-Québec interconnection scenario. Would Hydro purchase electricity from Hydro-Québec, or would it wheel its own power over the HQ transmission system?

b) In either case, please provide and explain Hydro's estimates of the costs involved.

c) Please explain why this least-cost option is not included in the derivation of expansion costs (Table 1) in the Network Addition Policy.

LAB-NLH-63. Re: Labrador Expansion Study, pages 19 and 73 (pdf)

Preamble:

> Table 3 (page 19) provides a Baseline Coincident Peak forecast for Labrador West growing from 342.4 MW in 2018 to 382.9 MW in 2043.
>
> Table 2 of Appendix B (page 73) shows these same values in the column identified as "baseline peak", and adds separate columns for "Data Centre", rising from 27.1 MW in 2020 to 51.5 MW in 2022 and remaining at that level through 2043, and a final column "Coincident Peak with Alderon", which appears to add 65 MW to the "Coincident Peak with Data Centres" column, from 2022 through 2043.
>
> Note 9 specifies that the baseline peak load forecast includes Hydro Rural, IOC and Tacora.

a) Do the values of "0" for Data Centres in 2018 and 2019 imply that there are no data centre loads included in the Baseline Peak? If not, please specify the amounts of data centre loads that are included in the Baseline Peak column.

b) Please explain the source and justification for the forecast of data centre loads growing from 27.1 MW in 2020 to 51.5 MW in 2022, and remaining at that level through 2043.

c) Please provide an update on the Alderon project, including Hydro's estimate of the likelihood that it will represent a 65 MW load starting in 2022.

LAB-NLH-64. Re: Labrador Expansion Study, p. 79 (pdf)

Citation:

Table 5: Overview of CPW of Preferred Alternatives and Transfer Capacity

Alt	Description	Forecast (MW)	Winter Firm Capacity (MW)	Non-Firm Capacity (MW)	Estimated Cost ($ million)	CPW ($ million)
4	WTS Upgrades (Baseline)	383	252	387	15.1	13.2
5	WTS Upgrades (Low Incremental)	434	252	454	31.7	27.6
17	315 kV Transmission Line from BLK to FLK with 46 kV connection from FLK	499	499	600	153.2	148.1

Please explain the correspondence between the three projects listed here and those found in Table 1 (Expansion Cost Derivation) of the Network Addition Policy.

LAB-NLH-65. Re: Network Addition Policy, page 20 (pdf)

Citation:

> This section will apply to determine the required Upstream Capacity Charge to supply demand requests of greater than 200 kW from an Applicant.

a) Please confirm that, for demand requests of up to 200 kW from an Applicant, there is not Upstream Capacity Charge.

b) Please explain what tools, if any, are available to Hydro if it suspects that two or more demand requests of under 200 kW are from related companies.

LAB-NLH-66. Re: Network Addition Policy, pages 21-22 (pdf)

Citation:

> Upon receipt of an Applicant's Demand request of 1500 kW or greater, Hydro will conduct a preliminary assessment to determine if compliance with the request would require acceleration of the Transmission Expansion Plan.
>
> If acceleration of the Transmission Expansion Plan is required, Hydro will determine the Expansion Advancement Cost. This cost reflects the difference between the cost of acceleration of the Transmission Expansion Plan and the value to existing Customers from plan acceleration. The value to existing Customers will be determined based the forecast reduction in Expected Unserved Energy resulting from the capital

> advancement. However, the credit provided based on the Expected Unserved Energy value to Customers will not exceed 50% of the cost of acceleration of the Transmission Expansion Plan. The procedures used to determine the Expansion Advancement Cost are provided in Appendix B to this Policy.
>
> The Upstream Capacity Charge will then be computed as the Expansion Advancement Cost less the Basic Capacity Investment Credit and, when applicable, less the Demand Revenue Credit.

a) Please explain what baseline will be used for the timing of the Transmission Expansion Plan, in order to determine whether or not a project results in its acceleration.

b) Please provide a numerical example of the computation of the Upstream Capacity Charge for a project of more than 1500 kW which results in acceleration of the Transmission Expansion Plan.

LAB-NLH-67. Re: Network Addition Policy

Preamble:

> Because the increments of transmission expansion projects are “lumpy”, it is possible that a relatively small demand request may result in the need to proceed with a relatively large expansion project.

For a hypothetical situation where a 5 MW demand request results in a $20 M expansion project, please estimate:

a) the Upstream Capacity Charge that would be required of the customer,

b) the resulting annual revenue requirement increase,

c) the annual revenue requirement increase that would be borne by existing customers, and

d) the resulting average rate increase, once the capital cost is fully included in rate base.