Paul D. Dicks KC
Lawyer
T 709.570.7253
E pdicks@bensonbuffett.com

Suite 900 Atlantic Place
Water Street, P.O. Box 1538
St. John's, NL
Canada A1C 5N8

December 12, 2022

VIA EMAIL

Board of Commissioners of Public Utilities
Prince Charles Building
210-120 Torbay Road
St. John's, NL, A1A 2G8

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – Non-Firm Rates Application

In relation to the above noted matter, please find enclosed the Requests for Information of Blockchain Labrador Corporation.

We trust you find the enclosed to be in order.

Yours truly,

BENSON BUFFETT PLC INC.

PAUL D. DICKS, Q.C.
PDD/lw

ecc.

Board of Commissioners of Public Utilities
Cheryl Blundon
PUB Official Email
Island Industrial Customer Group
Dean A. Porter, Poole Althouse
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox and Palmer

Iron Ore Company of Canada
Greg Moores, Stewart McKelvey

Labrador Interconnected Group
Senwung Luk, Olthuis Kleer Townsend LLP
Consumer Advocate
Dennis Browne, KC, Browne Fitzgerald Morgan and Avis

Newfoundland and Labrador Hydro
Shirley Walsh
NLH Regulatory
Kimberley Duggan

Envoum Corp.
Ali Amadee, Dentons Canada LLP

Newfoundland Power Inc.
Dominic Foley

IN THE MATTER OF the
Electrical Power Control Act
1994, SNL 1994 Chapter E-5.1
and the *Public Utilities Act*
RSNL 1990 Chapter P-46; and

IN THE MATTER OF an Application
by Newfoundland and Labrador Hydro
("Hydro") for approval of a rate for
Non-Firm Service in Labrador

TO: The Board of Commissioners of Public Utilities

REQUESTS FOR INFORMATION OF BLOCKCHAIN LABRADOR CORPORATION

Power Sales - General

1. Does Newfoundland Labrador Hydro ("Hydro") sell export power ("Export Power Sales") through any corporation other than Nalcor Energy Marketing Corporation ("NEMC")? Provide details on the quantity of export power sold by Hydro, NEMC and any related entities, where such power was sold and a breakdown of the gross revenue, cost of sales and net profits in each year such power was sold.

2. Prior to the incorporation of NEMC on March 24, 2014, did Hydro make any External Power Sales? If so, in what manner and through what entity?

3. What has been the amount of power available for export sale since January 1, 2018? Provide a monthly breakdown of power sold and unsold since January 1, 2018.

4. Has Hydro or any of its related corporations, including NEMC, lost money on Export Power Sales? What were the reasons for the losses? What are the fixed costs of export sales? How much Export Power has to be sold and at what assumed price(s) to break even?

5. How much of the Average Surplus Recapture Energy in Tables 3, 4 and 5 of Schedule 1, Attachment 1 of the Application cannot be exported because of the transmission capacity limitations?

6. How much of the non-firm demand in Labrador can be met from the existing surplus "Recapture Energy" which cannot be exported? Why does Hydro consider this to be a cost rather than an additional revenue source that it does not now have? If it cannot be exported, why does Hydro state in Section 5.1 of Schedule 1 Attachment 1 that the "provision of

non-firm service on the Labrador Interconnected System will result in reduced energy available for exports"?

7. What is the planned utilization for energy that cannot be exported or sold in Labrador or on the island?

8. Does Hydro or any of its related corporations, including NEMC, have any long-term contacts for Export Power Sales? If so, provide details as to quantities sold, gross and net revenues and a comparison with the prices in the New England Mass Hub and New York Zone A.

9. Is power exported and sold to places other than New York Zone A and New England Mass Hub? If so, provide a list of such places, quantities sold, the prices at which sold, gross revenue, a breakdown of the cost of sales, the net profit derived therefrom on an annual basis and a pricing comparison with New York Zone A and New England Mass Hub.

10. How is the power transmitted? Is any power exported other than through Quebec?

11. How much is paid for transmission line charges and to whom? How are these calculated? Are these costs fixed regardless of usage? How often and in what manner can those charges be varied? What are the charges for the use of the transmission lines providing access to the New York and New England markets and how are they determined? Is any transmission capacity sold to other entities? If so, please provide specifics with respect to amounts sold and gross and net revenue derived therefrom.

12. What is the quantity of the line losses due to transmission from the Province into the New York and New England markets?

13. Does Hydro charge any rates that have not been approved by the PUB? Has Hydro applied for rate increases outside of the general rate application prior to this application? Have they been approved or not?

November 30, 2022, Hydro Presentation

LIG Service Requests

14. With respect to Slide 4:

    a. When was the additional firm load restriction of 200 kW per customer implemented in Labrador East and Labrador West?
    b. What was the rationale for the restriction?
    c. To which customers does it apply?

d. Are there any exceptions?
e. Does it apply to any or all of the industrial customers in Labrador?
f. What was the form of implementation?
g. What approvals were required? Were these sought and approved?
h. If this restriction has been implemented, how does this reconcile with the comment on Slide 25 that "Hydro *plans to extend regulation* limiting firm load additions to 200 kW per customer". [Emphasis added]
i. How would the approval of firm load applications to serve cryptocurrency customers create a risk of materially increasing existing customer rates on the LIS?
j. How much power has to be used for blockchain operations for a customer to be deemed to be a cryptocurrency customer?
k. Will Hydro refuse power to data centres which have cryptocurrency operations? How will they be identified and differentiated from cryptocurrency customers? Will Hydro deny power if it learns that a portion of a customer's operation includes cryptocurrency mining?
l. What has been the gross revenue paid to Hydro by cryptocurrency customers since 2015?

LIS Non-Firm Rate Background

15. With respect to Slide 5:

a. What was the new LIS Network Additions Policy ("Nap") that was implemented in March 2021?
b. With which parties did Hydro make a Settlement Agreement requiring it to review whether the non-firm service offering was reasonable to implement? What was the basis for determining reasonableness? What were the terms of the Agreement?
c. What are the limited number of customers identified in the June 2021 feasibility report? Who were they? What was the assumption(s) respecting the amount of power to be used by or allocated to each such customer? What power, if any, has been allocated?
d. Where and to whom is energy in excess of monthly firm load forecasts sold?
e. What is the source and amount of the "surplus Recapture Energy"? Does it include any energy besides the Recapture block of 300 MW referred to Section 3.2 of Schedule 1 Attachment 1 of the Application? How much of the surplus Recapture Energy would be available without the Recapture block?
f. How does the "surplus Recapture Energy" relate to the determination of the excess monthly load forecasts?
g. How much of the "surplus Recapture Energy" is sold outside the Province, where and at what price? What has been the net revenue?
h. Has Hydro incurred any additional capital cost to make non-firm power available in Labrador?

16. If not answered in response to prior questions, in the period from January 1, 2018, to the present, on a monthly basis:

    a. How much energy has been sold by Hydro and/or NEMC? Where has it been sold and at what prices?
    b. What amount of energy has been deemed to be in excess of monthly firm load forecasts to the Labrador Industrial requirement? Is this the same as that in Table 1 of section 2.1 page 3 of Schedule 1 of the Application? Has any not been sold?
    c. How far in advance is the determination of the excess monthly load forecasts made?

17. What is the current forecast for excess energy in Labrador and where does the forecast originate?

Non-Firm Rate on Island Interconnected System ("IIS")

18. With respect to Slide 6:

    a. How have incremental costs changed on the IIS?
    b. If Holyrood fuel is not expected to be an incremental cost, what is the rationale for including it as a potential cost of non-firm energy? Please explain with reference to Slides 6 and 13 and the Application.
    c. If not answered in response to prior questions or differentiated therein, does Hydro export and sell any power in excess of firm island load? If so, provide an accounting on an annual basis from January 1, 2018.

Non-Firm Rates Review & Interruptible /Capacity Assistance in NL

19. Is the reason that Holyrood is being maintained for reliability to meet the firm requirement of customers due to the unreliability of the Labrador Island Interconnection line?

20. With respect to Slide 8, what are the material differences in service obligations for interruptible load/capacity assistance and non-firm or surplus /excess energy?

Interruptible/Capacity Assistance

21. With respect to Slide 9:

    a. Is all the Labrador curtailable power covered in Table 2 of Schedule 1, Attachment 1 of the Application?

b. How does Hydro define and differentiate between interruptible and non-firm power? How much power falls into each category and to whom is it supplied?
c. Do the load forecasts include interruptible power?
d. What capacity additions are planned to reflect interruptible/capacity assistance, if any?
e. What are the material differences in service obligations with respect to interruptible and non-firm power?
f. Why is the New England Mass price not included in the calculation of the Imbalance Energy Charge?

22. With respect to Slide 9:

    a. What power is normally included in load forecasts? Does it include interruptible power?
    b. What capacity additions are currently under consideration? Are these capacity additions being generated by anticipated customer demand increases? If so, who are those customers and what are the anticipated energy demand increases? How do these relate to the load forecasts set out in Schedule 1 Attachment 1 Appendix A?

23. With respect to Slide 10:

    a. What contracts does Hydro have for interruptible load/capacity assistance power on the Island Interconnected System?
    b. How will the construction of the transmission interconnection between Muskrat Falls and Happy Valley-Goose Bay affect firm, interruptible and/or curtailable power? When will it be built and/or commissioned and/or in service? How much power will be carried on the lines; to whom will it be made available; and at what rates? Please explain with reference to Schedule 1 Attachment 1 Appendix A.
    c. Has Hydro curtailed any of Newfoundland Power's 12 MW curtailable load since January 1, 2018? Has any compensation been paid?
    d. What additional interruptible/capacity assistance agreements is Hydro considering and why? What is the quantity of power and which customers will be affected?
    e. Does Hydro pay compensation or give credits for interruptions that it requests or requires?

24. Provide an accounting and breakdown of the quantity of non-firm sold on the island and Labrador; the prices at which it was sold; gross revenue; and the net profit derived therefrom on an annual basis since January 1, 2018.

25. With respect to Slide 11,

    a. What are the additional capital costs for curtailable power presently available in Labrador, if any?

26. With respect to Slide 12:

    a. What are the rates charged for interruptible and surplus/excess power by Manitoba Hydro, BC Hydro, Hydro-Quebec and New Brunswick Power. Provide details as to how they are calculated including whether and to what extent they are based on export sales?
    b. Do any of Manitoba Hydro, BC Hydro, Hydro-Quebec and New Brunswick Power charge a lower rate for surplus power sold either insider or outside the province in which the utility is located?
    c. Which of the other Canadian utilities pay customers a credit to reduce their available firm load as referenced in Section 5.1 of Schedule 1 Attachment 1.
    d. Does Manitoba Power sell surplus power at a lesser price than that charged for firm power? If so, what is the price difference and how is it calculated?
    e. Does Manitoba Power sell power from water it would otherwise spill for a lower price in export markets? What is the price differential?
    f. How does New Brunswick calculate its incremental cost for interruptible energy before adding the 0.9 cents per kWh on peak and 0.3 cents per kWh off peak referenced in Section 5.1 of Schedule 1 Attachment 1? How does the price of surplus or curtailable power in New Brunswick compare with the price at which export power is sold?
    g. Where does New Brunswick export power?
    h. In British Columbia, is the price of "Freshnet Energy" referred to in Section 5.1 of Schedule 1 Attachment 1 greater or less than the cost of firm energy? Is it set at the value of export power or the Mid-Columbia wholesale price?
    i. How much energy does Hydro-Quebec provide to cryptocurrency customers? How much of that energy is firm, non-firm and/or interruptible? What rates does Hydro-Quebec charge to cryptocurrency customers for each of the categories of power it supplies? Is it the same for fixed and interruptible and/or curtailable power? Are power rate increases limited on a monthly or annual basis?
    j. Has Hydro-Quebec advised that power that is currently deemed surplus is anticipated to be used in the development of new markets within Quebec? Is the price of that power tied to export sales value or will it be supplied in accordance with the general rates?
    k. Is Hydro-Quebec limited in the amount of power it can curtail to cryptocurrency customers? If so, explain the limitations. What period of notice is Hydro-Quebec required to give before curtailing power?
    l. Does Nova Scotia Power offer a demand charge discount on demand in excess of contract demand?

m. Does any Canadian utility sell domestic power at a rate based on the price at which export power could be sold? If so, name the utility and the basis on which such rates are established differentiating the rates for the categories of domestic power (i.e. firm, interruptible, non-firm and/or surplus excess energy)
n. Has any Public Utility regulator in Canada approved a rate for domestic power at the price that could be obtained for export power?
o. Do USA utilities charge non-firm rates? How are they calculated?
p. Why does a network grid result in less requirement for non-firm arrangements than a radial grid?
q. Which of the radial grids charge a non-firm rate based on the export value of energy in another market?
r. Does NL Hydro store any of its surplus power in any of its reservoirs? Does it manage its water resources so that water that would otherwise have to be spilled is utilized and other water resources conserved?
s. Does NL Hydro deem or designate any of its current power supply as "heritage" pool electricity?

Non-Firm Energy in NL

27. With respect to Slide 13:

a. If not previously answered, what has been the price differential between firm and non-firm energy prices in Labrador from January 1, 2018.
b. How is Hydro's current approach to pricing of non-firm energy using incremental cost "relatively consistent" with Canadian utility practice?
    i. Which of the other Canadian utilities uses the same approach as Hydro?
    ii. Which do not and how do they vary?
c. If not answered in response to question 26, is Hydro's proposal to price non-firm energy based on the export value in the New York and New England markets consistent with the rate charged by any other Canadian utility or a rate approved by any other Canadian Public Utility regulator? If so, identify the utilities, the regulators and how the rates are established.

LIS Non-Firm Rate & Pricing

28. With respect to Slide 15:

a. How much non-firm capacity has been available on the LIS since January 1, 2018? How much has been sold in Labrador? If not previously answered, has any of this energy been sold outside the province? If so, provide an accounting of the quantity of External Power Sales of the non-firm energy, differentiated by region (if applicable), the prices at which it was sold, gross revenue, and the net profit derived therefrom on an annual basis.

b. How would a non-firm energy rate provide flexibility to ensure that there would be no negative impacts on existing firm customers that could not be achieved with an interruptible rate?
c. How does the proposed non-firm rate which would be established with reference to lost net export revenue "continue the use of incremental cost in establishing the pricing of non-firm energy" which is stated in Slide 6 to have "historically been based on fuel cost incurred to provide service"?
d. Is any of the non-firm energy now provided as interruptible power? Provide details as to quantity, distribution and pricing.
e. Why does an interruptible rate not provide adequate flexibility for frequent load curtailments to ensure no negative impacts on existing firm customers?

29. With respect to Slides 16:

a. Who will provide the forecasted net market prices to Hydro to determine pricing?
b. From January 1, 2018 to December 31, 2022, have there been forecasted net market prices? Who provided them? How did these compare with actual?
c. Is the Imbalance Energy Charge established as an annual rate? Has an annual rather than a monthly model been considered for non-firm power? If so, how does this compare with the current proposal?
d. How would a three-year average pricing compare?
e. Will the rates be re-calculated once actuals are known? If the prices are lower, will Hydro refund to customers?
f. How will differential pricing of on and off-peak periods lower the probability of interruption?
g. Does Hydro have a model of on and off peak pricing and a projection of how much power will be used in on and off-peak hours? If so, provide a breakdown by customer.

30. With respect to Slide 17:

a. Are the prices in the table the prices at which Hydro and its related companies sold power? If not, what were the gross revenue prices and the cost(s) of sales? Was there available power that either couldn't be sold or was sold at a discount? Were export sales profitable in 2020, 2021 and 2022?
b. Why are the New York Zone A prices forecast to be generally lower than the New England Mass Hub? Has this been the case in the past? How does this forecast compare with past experience? If not answered previously, how much power has been sold in the New England Mass Hub since January 1, 2018, and at what prices compared with New York Zone A? Has any Labrador power been sold elsewhere?

31. With respect to Slide 18:

   a. Are the prices in the table gross or net prices? If gross, what are the anticipated net revenue forecasts. Provide details on the anticipated amount of power sales, fixed and operational costs, etc.
   b. Who provided the price forecasts for February and July 2023?
   c. Is Hydro involved with the sale of power from the Upper Churchill? Where is it sold and what is the net revenue realized from the sale of that power?
   d. If not answered previously, what has been the historical weighting of power sold in New York and New England since January 1, 2018 on a monthly basis specifying on-peak and off-peak?
   e. Are the on-peak and off-peak periods the same year round and from year to year? Are the proposed on-peak and off-peak periods in Section 2.3.3 of Schedule 1 of the Application the same as in New York and New England? If not, please detail the variations in those markets and how they compare with peak usage in Labrador East, Labrador West and on the Island.

32. With respect to Slide 20:

   a. Is Hydro proposing to set the same rate for non-firm power for Labrador East and Labrador West?
   b. Is the net revenue from export sales the same for Labrador East and Labrador West? How are transmission line losses calculated and accounted for?
   c. What additional common transmission investments will result in additional non-firm capacity being increased? What is the location, timing, cost and implementation dates of such investments?
   d. Is Hydro planning any capital investments besides transmission investments that will increase available energy? What are the timing, cost and implementation date?
   e. Are any upgrades planned for the existing turbines at Churchill Falls (the "Upgrades")? Please provide details with respect to the Upgrades planned, estimated costs, timing and estimated additional capacity and energy resulting from those Upgrades. What is the present plan for the sale(s) and rates to be charged for such additional energy? Will any of this be available in Labrador? Will any applications be made to the PUB?
   f. Are any transmission upgrades or additions planned with respect to the Churchill Falls? What additional capacity, energy and/or transmission loss reductions are anticipated?

33. With respect to slide 21:

   a. Is all of the non-firm load power still available?
      i. Has any been allocated to any customers? If so, provide a breakdown of the customers, the amount of power made available to them, the date when

such power was provided and the specifics of any contracts including the rate and duration.

ii. Is the rate charged one currently approved by the PUB? If so, which one? Does Hydro propose to continue invoicing the existing rate or the new non-firm power rate if approved?

iii. Is Hydro's rate for such power based on the net value of export power? If not, why not?

b. What is the anticipated usage of non-firm power in Western Labrador? How much is forecast to be available to be sold as export power?

c. If not answered in response to previous questions, has any surplus available power in Western Labrador been sold since January 1, 2018? If so, provide an accounting of the quantity of External Power Sales of the non-firm energy, the prices at which it was sold, gross revenue, and the net profit derived therefrom on an annual basis.

d. How much of the non-firm power is forecast to be used in Labrador West and Labrador East?

e. If all the surplus power is used in Western Labrador, how will the market price be determined and weighted between the New York and New England markets as well as off-peak and off-peak periods as per slide 18 of the Presentation if there are no sales?

f. What has been the location, number and durations of interruptions since January 1, 2018 in Labrador and the reasons therefor?

34. With respect to Slide 23:

a. What are the names of the nine parties which have made application for the non-firm capacity to be made available in Labrador East and West and the quantities of powere they have requested?

b. Which of these are still current? Have any indicated that they will not be proceeding? Have any been eliminated? If so, why?

c. Who are the customers to be provided with the non-firm capacity? Has any already been allocated? If so, to whom, in what quantities and when?

d. If all of the non-firm power is not taken up what appears to be four assumed customers, is it still Hydro's intent to make it available first to existing non-firm customer in accordance with term 16 of on page 3 of Schedule 2 of the Application.

e. What is the name of the additional cryptocurrency operation requesting non-firm service that Hydro deems to be not unreasonable? Is it included in either the nine customers or the four among whom the non-firm power is proposed to be distributed? When was the application submitted? How much power was requested? Why does Hydro deem the request "not unreasonable"? Has Hydro deemed any of the other customers unreasonable? If so, why?

35. With respect to Slide 24:

  a. What are the Firm Industrial Customer Loads and what are the contracted amounts of power on order? Is any of the non-firm power to be allocated to those customers?
  b. What are the Interruptible Industrial Customer Loads, who are the customers and what are the contracted amounts for each? Has or will any of the non-firm power be allocated to those customers?
  c. How will the implementation of the non-firm services limit the ability of the IOC and Tacora to exceed their contracted interruptible load availability?

36. With respect to Slide 25:

  a. When will the system impact studies for mining load additions in Labrador West be concluded? Have they been started? What are the potential mining load additions under consideration?
  b. Is there existing service capacity in Labrador East? Please specify the amount and availability?
  c. If not answered in response to question 23, has the Muskrat Falls and Happy Valley transmission interconnection been completed? When will it become operational? What are the firm service requests in Labrador East that Hydro expects will fully utilize the Muskrat Falls power? Why are the current requests for power that is not available deemed to be firm power request rather than surplus? How do these differ from the requests from customers in Labrador West?
  d. Why is Hydro discriminating against cryptocurrency customers?
  e. If the Labrador Interconnect Link from Muskrat Falls to the Island cannot be made to work or does not achieve sufficient reliability, will Hydro make any of the power available for use in Labrador?

Island Industrial Non-Firm Rate

37. With respect to slide 27:

  a. Does Hydro plan to apply to the Public Utilities Board ("PUB") for a new rate based on the potential value of energy used in excess of firm load on the island either as interruptible and/or non-firm/curtailable power in the New York and New England markets? If so, when will that application be forthcoming?
  b. Will the proposed pricing be the same as that proposed in this application?
  c. How much non-firm power is currently available on island?
  d. How much, if any, of the Muskrat Falls power will be surplus?
  e. How much capacity exists on the power line to Nova Scotia for export sales?
  f. Are there existing rates for power transmission on the lines that Hydro would have to use to access the New York and New England markets? What are those rates?

Does Hydro have contract with other utilities for the use of such transmission lines? What are the terms of those contracts including the rates and durations?

g. What are the gross and net revenue forecasts from potential island export sales?
h. Will Labrador and island non-firm power rates be balanced or one used to subsidize or off-set the other?
i. What is the forecast costs to customers and the gross and net revenues to Hydro if the application is approved?
j. If not previously answered, do any other utilities with an interconnection to the North American grid determine the price of interruptible, non-firm or surplus power based on the potential revenue from export sales?

38. With respect to slide 28:

    a. How does Hydro plan to enhance the non-firm rate option in the future to consider avoidance of spill energy? Will such enhancement take the form of lower prices?
    b. When and in what quantities is spill energy available?
    c. Are there possible storage options for such spill energy elsewhere in the system?
    d. Will any of the spill or other energy be made available to any hydrogen generation proposals?
    e. What is the anticipated increased timing on non-firm price updates?

39. With respect to Slides 30, 17 and 18:

    a. What are Hydro's forecasted revenues if its application is approved? Provide specifics with respect to on-peak and off-peak consumption and pricing.
    b. By how much and what percentage will this increase the rate for non-firm energy?
    c. Is Hydro planning to propose that the revenue from the LIS Non-Firm Rate be allocated back to Labrador customers? If not, why not? If so, will it be for the benefit of the industrial customers?

Application

40. How will the reliability of the Labrador-island link affect the proposed pricing of the non-firm rate for the IIC? Why does Hydro propose to charge the higher of the cost of thermal generation or the net value of export power as indicated in Section 5.2 of Schedule 1 Attachment 1?

41. With respect to paragraph 7, does Hydro propose that any increased demand in Labrador be treated as non-firm power? If not, what are the criteria that Hydro will apply to deem power supplied to some customers as firm and other as non-firm?

42. With respect to paragraph 10, what is the anticipated number of customers with a load requirement of 1.5 MW. Who are they?

43. With respect to paragraph 13, what are the additional firm transmission investments referred to? How much additional capacity will result from them? Will all of this be considered non-firm power?

44. With respect to paragraph 14, how is the proposed rate consistent with the non-firm rate charged to IIC and the Labrador Imbalance Rate?

45. What are the delivery costs referred to in paragraph 15?

Schedule 1

Section 1

46. If an Island Industrial Customer increases the Power on Order, is this increase then deemed firm power?

47. Given the problems with the island interconnection, does Hydro still anticipate that Holyrood will operate at minimum load to support system reliability? If not, what are its current projections?

48. Will the delayed commissioning of Muskrat Falls affect the pricing of non-firm power?

Section 2

49. What is the source of the non-firm transmission capacity identified in Table 1? Why was it not identified earlier?

50. Is the provision of 5 MW of interruptible load to each of IOC and Tacora part of or in addition to the non-firm loads specified in Table 1. When was this power allocated to IOC and Tacora? Is it being used? If so, when and to what extent? Is any of the other power allocated to IOC and Tacora not fully utilised? If so, when and to what extent?

51. How much export power is now sold in New York and New England. How will that change with the commissioning of the Project and the Maritime Link? Does Hydro's projection of the weighted average between New York and New England reflect current sales or the future distribution when Muskrat Falls power becomes available for sale? How much

additional energy will be available for export sale upon commissioning of Muskrat Falls? Will all that power be sold in New England?

52. How does Hydro's statement in section 2.3.5 that the non-firm rate in Labrador will often be lower than the firm energy rate accord with the rates shown on Slide 18 and in Table 3? Are any of those rates lower than the firm energy rate in Labrador?

Section 4

53. Has Hydro prepared a comparison of projected monthly Holyrood TG5 fuel costs with Tables 3 and 4 for the periods from 2020 to 2025?

Schedule 1 Attachment 1

54. What has been the load growth in Labrador by industry since January 1, 2018?

55. If not answered previously, how many of the applications in Table 1 are still current? Who are they and what are the load requests?

56. With reference to Section 5.2, what is Hydro's current energy supply incremental cost? Why does the opportunity cost of lost export sales reflect only the New York Market and not New England as in footnote 12? What other supply source could be utilized if the Recapture Energy is fully utilized?

Appendix A

57. How does Hydro plan to market the additional available capacity in Labrador East when the Muskrat Falls transmission line extension and Muskrat Falls and Happy Valley Terminal Station terminal upgrades are completed? When will these be completed?

58. In Table 2 on page 2, the load forecast for Labrador West in 2021 had a baseline peak of 377.3 MW. Please explain with reference to the TwinCo block of 225 MW and tables 3 and 4 of Schedule 1 Attachment 1 on page 6.

59. Why is there only 2.2 MW of forecast growth from 2021 to 2030 in Labrador West? With such little growth, why has Hydro sought to limit the number of blockchain customers rather than provide a special rate as did Hydro Quebec?

60. What are the plans to find a market for the surplus excess power that cannot be exported and which will not be utilized in Labrador?

61. Why does the probability of load interruptions increase as the load increases?

Schedule 3

62. What are the average system losses on the Labrador Grid for the last five years?

<u>DATED</u> at St. John's Newfoundland and Labrador, this 12th day of December, 2022.

Benson Buffett PLC Inc.

Per: Paul D. Dicks
Paul D. Dicks, K.C.

Per: Meg Reynolds
Megan Reynolds