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March 29, 2023

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Cheryl Blundon
Director of Corporate Services and Board Secretary

Re: Application for Non-Firm Rates – Revision 1

Further to Newfoundland and Labrador Hydro's ("Hydro") correspondence dated March 15, 2023,[1] enclosed is Revision 1 of Hydro's Application for Non-Firm Rates. The revisions relate to the date on which the Non-Firm Rates will be effective, the establishment of a minimum price for the non-firm energy charge for customers on the Labrador Interconnected System and Island Industrial customers, and revisions to Hydro's Supply Cost Variance Deferral Account definition, to allow non-firm revenues from Labrador Interconnected System customers to contribute to rate mitigation for the Island Interconnected System.

Hydro is proposing that the effective date for the proposed non-firm rates be set as the first day of the month that is at least two months subsequent to the Board of Commissioners of Public Utilities' approval of the rate design. This period will enable Hydro to work with the participating customers to implement the communication and billing processes required for rate implementation. Details on the requirement for this implementation period are provided in Hydro's responses to requests for information ("RFI") PUB-NLH-005 and PUB-NLH-007 of this proceeding.

Hydro's proposal to reflect a minimum price in the proposed non-firm energy rates is similar to the structure of BC Hydro's non-firm rates for incremental/surplus energy, which are based on the greater of the minimum price ($0 plus an adder per MWh) or the approved market price.[2] The use of zero in computing the minimum price at BC Hydro reflects that the forecast market price of energy can be volatile and even result in negative pricing in some periods.

While the likelihood of a forecast negative market price in Hydro's proposed non-firm rate may be low, due to the use of an average monthly forecast market price (i.e., which would be expected to have lower price volatility than daily market pricing), Hydro believes it is prudent to establish a minimum price to avoid the possibility of negative pricing for non-firm energy. Therefore, Hydro has proposed to establish a minimum price for non-firm rate based on the energy price component of the Rate 2.4L,

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[1] "Application for a Non-Firm Rate for Labrador - Clarification from Hydro on Issues – Hydro's Reply," Newfoundland and Labrador Hydro, March 15, 2023.
[2] The BC Hydro Freshet (Rate 1892) and Transmission Service Incremental Energy (Rate 1893) rate, which is based on the greater $0 plus an adder per megawatt-hour or the Intercontinental Exchange Mid-Columbia (Mid-C) Peak or Mid-C Off-Peak weighted average index price.

which applies to large General Service customers on the Labrador Interconnected System; this energy charge is currently 1.675 cents per kWh. The information on the record supporting the minimum price proposal is provided in Hydro’s responses to RFIs NP-NLH-004 and BKL-NLH-026.

Hydro is also requesting approval to enable revenues from the proposed non-firm rate for Labrador to be credited to the balance in the Supply Cost Variance Deferral Account to help offset the costs of supply from the Muskrat Falls Project. Hydro believes this approach is appropriate, as the increase in non-firm sales in Labrador will serve to reduce the value of export revenues that would have been available to support rate mitigation funding. Additional detail providing support for this proposal is provided in Hydro’s responses to RFIs PUB-NLH-004 and IC-NLH-005.

Hydro has revised Schedule 2 and Schedule 3 to reflect the minimum charge proposal and has attached Schedule 4 with the proposed revisions to the Supply Cost Variance Deferral Account definition.

Revisions to the application have been shaded grey for ease of reference. Any revisions to areas previously shaded grey will appear yellow, to allow for distinction between the original and Revision 1 of the application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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Application for a Non-Firm Rate for Labrador

Original Submission: September 15, 2022
Revision 1: March 29, 2023

newfoundland labrador hydro

An application to the Board of Commissioners of Public Utilities

Revision History

Revision No.	Revision Date	Location	Reason
1	29-Mar-2023	Legal Application, p.1, Style of Cause	Updated to reflect revisions made to the application's request
1	29-Mar-2023	Legal Application, p. 3, Item 11,	Added "Revision 1 of" to indicate the revision of Schedule 2
1	29-Mar-2023	Legal Application, p. 3, Item 13	Added "Revision 1 of" to indicate the revision of Schedule 2
1	29-Mar-2023	Legal Application, p. 4, Item 16	Added "Revision 1 of" to indicate the revision of Schedule 2
1	29-Mar-2023	Legal Application, p. 5, Item 18	Added to reflect Hydro's proposal for minimum price for non-firm rate on Labrador Interconnected System.
1	29-Mar-2023	Legal Application, p. 5, Item 19	Added to reflect Hydro's proposal for minimum price for non-firm rate on Labrador Interconnected System.
1	29-Mar-2023	Legal Application, pp. 5–6, Item 23	Added "Revision 1 of" to indicate the revision of Schedule 3
1	29-Mar-2023	Legal Application, p. 6, Item 24	Added to reflect Hydro's proposal for minimum price for non-firm rate for Island Industrial Customers
1	29-Mar-2023	Legal Application, p. 6, Section E	Added to reflect Hydro's proposal of non-firm rate revenues from Labrador Interconnected Customers (Rate 5.1L) to be transferred to the Supply Cost Variance Deferral Account.
1	29-Mar-2023	Legal Application, p. 6, Item 25	Added to reflect Hydro's proposal of non-firm rate revenues from Labrador Interconnected Customers to be transferred to the Supply Cost Variance Deferral Account.
1	29-Mar-2023	Legal Application, p. 6, Item 26	Added to reflect Hydro's proposal of non-firm rate revenues from Labrador Interconnected Customers to be transferred to the Supply Cost Variance Deferral Account.
1	29-Mar-2023	Legal Application, p. 6, Item 27	Added to reflect Hydro's proposal of non-firm rate revenues from Labrador Interconnected Customers to be transferred to the Supply Cost Variance Deferral Account.
1	29-Mar-2023	Legal Application, p. 6, Item F	Added to reflect Hydro's proposed effective date.
1	29-Mar-2023	Legal Application, p. 6, Item 28	Added to reflect Hydro's proposed effective date.
1	29-Mar-2023	Legal Application, p. 7, Item 29	Added to reflect Hydro's proposed effective date.

Revision No.	Revision Date	Location	Reason
1	29-Mar-2023	Legal Application, p. 7, Item 30(ii)	Added “Revision 1 of” to indicate the revision of Schedule 2
1	29-Mar-2023	Legal Application, p. 7, Item 30(ii)	Removed “and,” as additional items are being added to Hydro’s requests.
1	29-Mar-2023	Legal Application, p. 7, Item 30(iii)	Added “Revision 1 of” to indicate the revision of Schedule 2
1	29-Mar-2023	Legal Application, p. 7, Item 30(iii)	Added “and,” as additional items are being added to Hydro’s requests.
1	29-Mar-2023	Legal Application, p. 7, Item 30(iv)	Added to reflect Hydro’s requested changes to the Supply Cost Variance Deferral Account definition for Board approval.
1	29-Mar-2023	Legal Application, p. 7, Item 30	Added to reflect Hydro’s requested effective date for Board approval.
1	29-Mar-2023	Schedule 2, p. 1	Added definition of proposed minimum non-firm energy price.
1	29-Mar-2023	Schedule 3, p. IND-3	Added definition of proposed minimum non-firm energy price.
1	29-Mar-2023	Schedule 4	Added “and revenues from Rate No. 5.1L – Non-Firm Energy” to reflect the proposal of non-firm rate revenues to be transferred to the Supply Cost Variance Deferral Account.

Application

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

IN THE MATTER OF an application by Newfoundland and Labrador Hydro (“Hydro”) pursuant to Section 70 of the *Act* for approval of a rate for Non-Firm Service in Labrador, and other associated matters and for the revision of the Supply Cost Variance Deferral Account definition. (“Application”).

To: The Board of Commissioners of Public Utilities (“Board”)

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro, a corporation continued and existing under the *Hydro Corporation Act, 2007,*[1] is a public utility within the meaning of the *Act*, and is subject to the provisions of the *EPCA*.

2. Under the *Act*, the Board of Commissioners of Public Utilities (“Board”) has the general supervision of public utilities and requires that a public utility submit, for the approval of the Board, the rates, tolls, and charges for the service provided by the public utility and the rules and regulations that relate to that service.

3. Subsection 70(1) of the *Act* provides that a public utility shall not charge, demand, collect, or receive compensation for a service performed by it until the Board has approved a schedule of rates, tolls, and charges for the services provided by the public utility.

4. In a Settlement Agreement arising out of Hydro’s application for approval of its Labrador Interconnected System Network Additions Policy (“NAP”),[2] approved by the Board in

[1] *Hydro Corporation Act, 2007*, SNL 2007 c H-17.
[2] “Network Additions Policy – Labrador Interconnected System,” Newfoundland and Labrador Hydro, December 4, 2020.

Order No. P.U. 7(2021),[3] Hydro agreed to conduct a review of the feasibility of including a non-firm rate option to the NAP and to file a report with the Board by mid-2021.

5. Hydro filed the report "Feasibility of the Additions of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System" with the Board on June 30, 2021.[4] That report, provided as Attachment 1 to Schedule 1 of this Application, concluded that a non-firm rate is technically feasible for a limited number of customers on the Labrador Interconnected System.

6. To determine a just and reasonable rate for a non-firm service offering on the Labrador Interconnected System, Hydro has reviewed the approach to non-firm rates by other utilities as well as the non-firm energy rate that is currently in effect for Hydro's Island Industrial Customers ("IIC"). Hydro's Application generally reflects accepted utility practice in other Canadian jurisdictions.

7. With the interconnection to the North American grid, Hydro's marginal cost of energy on the Island Interconnected System is transitioning to the market value of exports. Increased energy usage by customers will decrease the energy available to export.

8. The current non-firm rate for IIC only considers thermal generation costs (i.e., fuel costs) in pricing the non-firm rate for IIC. To ensure the pricing approach for the non-firm rate reflects the change in incremental costs, Hydro is proposing a change in the pricing approach in the non-firm rate to IIC.

B. Non-Firm Service on the Labrador Interconnected System

9. Hydro has determined that there is available non-firm transmission capacity in Labrador that could be utilized to provide non-firm service to a limited number of customers at this time. The amount of available capacity projected for Labrador East and West is indicated in Section 2.0 of Schedule 1 to this Application.[5]

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[3] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 7(2021), Board of Commissioners of Public Utilities, March 17, 2021.
[4] "Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System," Newfoundland and Labrador Hydro, June 30, 2021.
[5] "Application for a Non-Firm Rate for Labrador," Newfoundland and Labrador Hydro, September 15, 2022, sch. 1, sec. 2.0, p. 3, Table 1.

10. Hydro must establish operational procedures and protocols to ensure that non-firm customer curtailments can be safely and effectively performed by operators at the Energy Control Centre. For this reason, the total number of interruptible customers availing of non-firm service must be limited. Therefore, Hydro is proposing only customers with a load of 1.5 MW or more will be considered for a non-firm energy rate option and each customer will be required to interconnect at transmission system voltages of 46 kV or higher.

11. To avoid negatively impacting reliable supply of firm load, customers would be required to curtail load within ten minutes of being advised by Hydro. Further evidence on the details of the proposed non-firm service are provided in Section 2.2 of Schedule 1, and the terms and conditions of the Labrador Interconnected System Non-Firm Rate Sheet provided in Revision 1 of Schedule 2 to this Application.

12. The available non-firm capacity is seasonal in nature, and is contingent on the firm load requirements for the regions. Hydro's proposal, as set out in Section 2.1 of Schedule 1 to this Application, is to equally share the available non-firm capacity among the customers that avail of non-firm service.

13. Once the available non-firm capacity is fully utilized in a region, Hydro would not add additional non-firm customers until additional firm transmission investments resulted in additional non-firm available capacity. Any additional capacity available due to additional firm transmission investments would be allocated through an open application process. Further details surrounding the non-firm service and its allocation is set out in Section 2.1 of Schedule 1 to this Application, as well as the terms and conditions listed on the Labrador Interconnected System Non-Firm Rate Sheet, attached to this Application as Revision 1 of Schedule 2.

C. Non-Firm Rate for the Labrador Interconnected System

14. Hydro proposes to base the rate for the non-firm service on the incremental cost of supply. As increased energy usage on the Labrador Interconnected System reduces the availability of exports, the incremental cost of supplying non-firm energy will reflect the market value of exports. As indicated in the evidence provided in Section 2.3 of Schedule 1 to this Application, the use of incremental costs in pricing of the sale of surplus energy is generally consistent with other Canadian jurisdictions. The proposed pricing approach is also consistent with current

Hydro practice, in particular, in the non-firm rate currently charged to IIC for excess energy consumption and in the Imbalance Rate applicable to excess energy sold to Labrador Industrial customers.

15. Hydro's proposed rate for non-firm service in Labrador is based on a forecast market price to be updated monthly. Because export revenues will be based on both the New York wholesale energy market price and the New England Massachusetts Hub energy market price, Hydro proposes to compute a blend of the two forecast market prices in determining the non-firm rate. Hydro considers a weighted average of the projected price (net of delivery costs) from these markets a reasonable approach to setting a rate reflective of the incremental cost for non-firm service. Please refer to Section 2.3.2 of Schedule 1 to this Application for further detail on the proposed computation of the rate.

16. The remainder of Section 2.3 of Schedule 1 to this Application provides evidence on Hydro's proposals that the Non-Firm Rate differentiate between peak and off-peak period based on forecast monthly average market values; that the Non-Firm Rate not include a demand charge; and, that the administrative charge be a monthly Basic Customer Charge equal to that applied for Island Interconnected System General Service customers with demands of 1,000 kVA or greater. These proposals are also contained in the Labrador Interconnected System Non-Firm Rate Sheet attached to this Application as Revision 1 of Schedule 2.

17. Approval of Hydro's proposed Non-Firm Rate for the Labrador Interconnected System would eliminate the requirement for the Secondary Energy Rate currently charged in Labrador for those customers on the Labrador Interconnected grid who are engaged in fuel switching. This rate has not been utilized for many years and CFB[6] Goose Bay, the only customer that availed of the rate, is no longer interested in fuel switching. The evidence supporting the proposed discontinuance of the Secondary Energy Rate is provided in Section 3.0 of Schedule 1 to this Application.

[6] Canadian Forces Base ("CFB").

18. Hydro believes it is prudent to establish a minimum price to avoid the possibility of negative pricing for non-firm energy. Negative pricing is possible if the non-firm price is established based solely on a market forecast.

19. Hydro has proposed to establish a minimum price for the proposed non-firm rate for the Labrador Interconnected System based on the energy price component of the Rate 2.4L, which applies to large General Service customers on the Labrador Interconnected System; this energy charge is currently 1.675 cents per kWh. This proposal is reflected in Revision 1 of Schedule 2. The information on the record supporting the minimum price proposal is provided in Hydro's responses to NP-NLH-004 and BKL-NLH-026 of this proceeding.

D. Island Industrial Non-Firm Rate

20. Hydro offers its Industrial customers on the Island Interconnected System a non-firm energy rate for a customer-specific MW block, which is in excess of their firm load. The energy price, which applies when using load in excess of firm load, is based upon Hydro's incremental energy costs at the time of delivery, plus an administrative fee and a charge for system losses. Historically, the energy costs have typically been based on the monthly Holyrood Thermal Generating Station ("Holyrood TGS") fuel cost.

21. With the impending commissioning of the Muskrat Falls Project, including the commissioning of the Labrador-Island Link ("LIL"), Hydro expects that the marginal energy cost on the Island Interconnected System to transition to the market value of exports.

22. However, in the short term, should the LIL not perform reliably during high load periods, it is possible that the Holyrood TGS may be selectively operated to provide energy to the system. In this circumstance, if IIC exceed their Power on Order and utilize their interruptible load (as they occasionally do), fuel at the Holyrood TGS may continue to reflect Hydro's incremental cost of serving the interruptible load.

23. To reflect the change in the incremental cost of supplying non-firm energy to the Island Interconnected System, Hydro proposes to amend the IIC Rate Sheets to reflect that, for most of the time, the incremental cost of providing non-firm energy will reflect the market value of exports. However, the Non-Firm Rate will continue to have the option to apply thermal fuel costs as an incremental cost to allow for the current uncertainty regarding the reliability of the

LIL. This proposal is discussed further in Sections 1.0 and 4.0 of Schedule 1 to this Application, and the amended IIC Rate Sheets is attached to this Application as Revision 1 of Schedule 3.

24. For consistency with the Non-Firm Rate for the Labrador Interconnected System and to ensure the non-firm price could not go below zero, Hydro proposes to establish a minimum price for the non-firm rate for the Island Industrial Customers based on the energy price component of the Rate 2.4L, which applies to large General Service customers on the Labrador Interconnected System; this energy charge is currently 1.675 cents per kWh. This proposal is shown on the revised Island Industrial Customer Rate Sheets, attached as Revision 1 of Schedule 3.

E. Amendment of the Supply Cost Variance Deferral Account

25. Hydro is also requesting approval to enable revenues from the proposed non-firm rate for Labrador to be credited to the balance in the Supply Cost Variance Deferral Account to help offset the costs of supply from the Muskrat Falls Project. Hydro believes this approach is appropriate, as the increase in non-firm sales in Labrador will serve to reduce the value of export revenues that would have been available to support rate mitigation funding.

26. Additional detail providing support for this proposal is provided in Hydro's responses to PUB-NLH-004 and IC-NLH-005 of this proceeding.

27. Hydro proposes to revise the Supply Cost Variance Deferral Account definition to credit revenues from non-firm sales on the Labrador Interconnected System to the deferral account. The revised Supply Cost Variance Deferral Account definition is included with this Application as Schedule 4.

F. Effective Date

28. Hydro requires a two-month implementation period from the approval date of the non-firm rate design to the effective date of the new non-firm rate design for both the Labrador Interconnected System and the Island Industrial customers to allow for implementation of the necessary communication process. Therefore, Hydro proposes that the effective date be set as the first day of the month that is at least two months subsequent to the date of the Board's approval of the rate design.

29. Details on the requirement for this implementation period are provided in Hydro's responses to PUB-NLH-005 and PUB-NLH-007 of this proceeding.

G. Hydro's Requests

30. Therefore, Hydro requests that the Board approve pursuant to subsection 70(1) of the *Act*:

    (i) The discontinuance of Rate No. 5.1L, Secondary Energy;

    (ii) Rate No. 5.1L, Non-Firm Energy, as set out in Revision 1 of Schedule 2 to this Application; []

    (iii) The modification of the IIC Rate Sheets, as set out in Revision 1 of Schedule 3 to this Application; and

    (iv) The revisions to the Supply Cost Variance Deferral Account as set out in Schedule 4 to this Application.

    all to become effective on the first day of the month that is at least two months subsequent to the date of the Board's approval of the rate design.

DATED at St. John's in the Province of Newfoundland and Labrador this 29th day of March, 2023.

NEWFOUNDLAND AND LABRADOR HYDRO

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Schedule 1

Evidence

Executive Summary

As part of the process surrounding the review and approval of the Network Additions Policy – Labrador Interconnected System ("Policy"), Newfoundland and Labrador Hydro ("Hydro") committed to conducting a review of the feasibility of the addition of a non-firm rate option. Hydro's report, filed with the Board of Commissioners of Public Utilities ("Board") on June 30, 2021,[1] concluded that a non-firm rate is technically feasible for a limited number of customers on the Labrador Interconnected System. To determine a just and reasonable rate for a non-firm service offering on the Labrador Interconnected System, Hydro has reviewed the approach to non-firm rates in other utilities as well as the non-firm energy rate that is currently in effect for Island Industrial Customers ("IIC"). Hydro's application for a Non-Firm Rate for Labrador generally reflects accepted utility practice in other jurisdictions.

As the amount of non-firm load requested by applicants for service on the Labrador Interconnected System is in excess of the non-firm capacity projected to be available, Hydro is proposing available non-firm capacity on the Labrador Interconnected System be shared equally among customers and service provided at transmission voltage with a rate reflective of the market value of exports (i.e., incremental cost of energy). The use of incremental costs in determining the price for non-firm energy usage is generally consistent with the practice in other Canadian utilities that have rates established for the provision of surplus/additional energy beyond what is provided on a firm basis. Hydro is also proposing to eliminate the Secondary Energy Rate on the Labrador Interconnected System, as this rate is no longer in use or required with the approval of the proposed Labrador Interconnected System Non-Firm Rate.

With the interconnection to the North American grid, the marginal energy costs for both systems should now consider the market value of exports. Hydro's proposed rate for non-firm service in Labrador is based on a blend of the forecast New York wholesale energy market price and the New England Massachusetts ("Mass") Hub energy market price, to be updated monthly. However, with the ongoing uncertainty on the reliability of the Labrador-Island Link ("LIL"), the proposed non-firm rate for IIC will need to continue to have the option to apply thermal fuel costs as an incremental cost in computing the non-firm rate. Continuing to charge IIC a non-firm rate based solely on fuel cost would be inconsistent with cost-based pricing when fuel cost is not expected to reflect Hydro's ongoing incremental cost of supply. Hydro is proposing to revise the non-firm rate for IIC to include the market value of exports as an

[1] "Feasibility of the Additions of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System," Newfoundland and Labrador Hydro, June 30, 2021.

option for determining the non-firm rate (i.e., consistent with the Labrador Interconnected System Non-Firm Rate).

Contents

List of Attachments

1.0 Background

The Board approved the Policy to be applied by Hydro on March 17, 2021.[2,3] As part of the settlement agreement to the regulatory proceeding examining the Policy, Hydro agreed to conduct a review of the feasibility of adding a non-firm rate option to the Policy and file a report with the Board by mid-2021.[4] Hydro filed a report on June 30, 2021 providing the results of Hydro's analysis which concluded that a non-firm rate is technically feasible for a limited number of customers on the Labrador Interconnected System.[5] A copy of the report is provided as Attachment 1.

In availing of a non-firm energy product, customers accept that the delivery of energy may be interrupted at any time. Non-firm customers must also understand that increased usage by customers on the Labrador Interconnected System with firm service will be prioritized and the amount of non-firm service may decline over time. However, non-firm customers receive the benefit of not being required to contribute to the cost of infrastructure additions to supply firm service. Over the past 12 months, Hydro has engaged in further discussions with applicants for service to assess potential interest in non-firm service, and has carried out system analysis consistent with the conditions presented in its report. Hydro is now proposing to implement a non-firm rate for customers supplied at transmission voltage on the Labrador Interconnected System.

Hydro currently has a non-firm pricing approach in effect for IIC. Specifically, non-firm energy purchases by IIC constitute energy consumption in excess of their Power on Order (i.e., when they are accessing interruptible demand). The non-firm energy price is currently based on the incremental fuel cost of the energy plus an administration fee of 10%.[6] While Hydro has continued to maintain the Holyrood TGS to reliably meet the firm requirements of its customers, the Holyrood TGS is planned to operate at

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[2] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 7(2021), Board of Commissioners of Public Utilities, March 17, 2021.
[3] The Policy is to ensure the costs associated with transmission upgrades are fairly allocated among the customers driving new load requests.
[4] In the "Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro" completed by The Brattle Group Inc. ("Brattle") in November 19, 2019, Brattle recommended that the Policy include a non-firm rate option whereby customers could select a surplus energy option when available with the understanding that they are subject to power supply interruptions when the system does not have capacity to provide service.
[5] "Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System," Newfoundland and Labrador Hydro, June 30, 2021.
[6] The non-firm price depends on the generation unit deemed to be at the margin, of which there have been historically three types: Holyrood Thermal Generating Station ("Holyrood TGS"), gas turbines, and diesel.

minimum load to support system reliability. As a result, the sale of non-firm energy would not be expected to increase the fuel costs of the Holyrood TGS.

Over the long term, Hydro expects the proposed non-firm rate will consistently be based on the forecast export values of surplus energy. However, in the short term, if the LIL does not perform reliably during high load periods, the Holyrood TGS may be selectively operated to provide energy to the system. In this circumstance, if IIC exceed their Power on Order and utilize their interruptible load (as they occasionally do), fuel at the Holyrood TGS will reflect Hydro's incremental cost of serving the interruptible load. Therefore, while Hydro is proposing to revise the IIC Non-Firm Rate to include the market value of exports as an option for the incremental cost (i.e., consistent with the Labrador Interconnected System Non-firm Rate), Hydro is also proposing to continue to have the option to apply thermal fuel costs as an incremental cost in computing the non-firm price.

As the marginal energy cost on the Island Interconnected System is transitioning to the market value of exports, it is appropriate to modify the non-firm rate available to IIC to reflect this change in incremental costs. Continuing to charge for non-firm energy based solely on fuel cost would be inconsistent with cost based pricing as fuel cost will no longer reflect the incremental cost of supply most of the time.

The pricing of non-firm energy reflecting the incremental cost of supply is the most common approach among other Canadian utilities that have rates in effect to sell surplus or additional energy. Hydro also applies this approach for the sale of energy in excess of the monthly forecast requirements of the Labrador Industrial customers. The Imbalance Rate on the Labrador Interconnected System applies to excess energy sold to Labrador Industrial customers; the price for the Imbalance Rate is based on the forecast average monthly market price. As mentioned earlier, Hydro also uses the incremental cost approach in setting the price for non-firm energy sales to IIC.

Hydro would normally update the non-firm rate for IIC as part of its General Rate Application ("GRA"). However, Hydro's GRA filing has been delayed while awaiting full commissioning of the Muskrat Falls Project ("Project"); rates implemented as a result of Hydro's next GRA may not be in effect until 2025. Prior to full Project commissioning, there will be extended periods of time when the market value of exports determines the incremental cost of supply on the Island Interconnected System. Therefore, to provide an efficient price signal to IIC, Hydro believes it is appropriate to revise the non-firm rate for IIC coincident with the implementation of the non-firm rate for the Labrador Interconnected System.

2.0 Labrador Interconnected System Non-Firm Service Proposal

2.1 Availability and Allocation of Non-Firm Transmission Capacity

Hydro's projections of its non-firm transmission capacity availability are presented in Table 1.

Table 1: Maximum Non-Firm Load for Labrador East and Labrador West (MW)

	Winter December to March	**Spring April to June**	**Summer July to September**	**Fall October to November**
Labrador East	28	43	58	38
Labrador West	20	50	50	50

Table 1 identifies the projected quantities (MW) of non-firm load that could be added to each region by season.[7] These projections have been presented in Hydro's discussions with the applicants for non-firm service on the Labrador Interconnected System.

The available non-firm capacity is indicative of the seasonal nature of the load requirements.[8] The actual number of interruptions and the amount of non-firm load that can be supplied is dependent upon variability in firm load requirements and the flexibility of non-firm customers to manage service interruptions that would be required to ensure Hydro satisfies its firm service obligations.

The projected available non-firm capacity also reflects the conclusion of a Temporary Service Agreement for non-firm service with BlockLab effective December 2022 and the historical use of non-firm load by Iron Ore Company of Canada ("IOC") and Tacora Resources ("Tacora").[9] Hydro would also continue the provision of 5 MW of interruptible load to each of IOC and Tacora as the provision of interruptible load is reflected in the service agreements of these customers.

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[7] The analysis was based on a premise that a maximum of 50 interruptions would provide an acceptable limit for customers and for reliable system operation. Table 1 identifies the quantity of non-firm load that could be added to each of the regions, by season, while maintaining a maximum planned number of interruptions to fewer than 50 occurrences. However, the non-firm service would not be limited to a maximum number of interruptions; non-firm service would be interrupted as often as necessary to ensure firm customer commitments can be met.

[8] Higher winter load requirements reduce what can be made available on a non-firm basis during the winter months. If the iron ore mines increase their load requirements during the non-winter months closer to their Power on Order (which they fully utilize during the winter), the amount of non-firm capacity that can currently be made available in Labrador West during the non-winter months would need to be reduced materially.

[9] The Temporary Service Agreement was approved by the Board in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 27(2018), Board of Commissioners of Public Utilities, August 10, 2018.

As Hydro has non-firm service load requests in excess of the non-firm capacity projected to be available, in discussion with the service applicants, Hydro proposed to share equally the available non-firm capacity among the customers that avail of non-firm service. Table 2 provides the projected allocation of non-firm capacity for each individual applicant that continues to express an interest in non-firm service on the Labrador Interconnected System.

Table 2: Non-Firm Individual Customer Allocation (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Labrador East[10]	5.5	8.5	11.5	7.5
Labrador West[11]	5	12.5	12.5	12.5

The actual number of non-firm customers and the amount of non-firm load is not yet final as the applicants will make their final decisions on whether to proceed with non-firm service based on the approved pricing methodology, terms and conditions for service, and the contribution requirements for interconnection. Once a non-firm rate and terms and conditions are approved, Hydro proposes to allocate the available non-firm capacity among the applicants that remain interested in non-firm service. However, there may be times when Hydro can permit non-firm customers to use more than their load allocation if there are no system constraints and if Hydro would not be required to operate standby generation to supply.[12]

For the purpose of allocation and monitoring the use of non-firm capacity, Hydro will maintain separate regions for Labrador East and Labrador West. When Hydro determines that the full non-firm capacity is utilized in a region, Hydro will not add additional non-firm customers unless additional transmission investments to provide firm service result in additional non-firm capacity becoming available in that region.[13] Hydro plans to update the Board on the customer response to the proposed non-firm rate in its quarterly reporting to the Board, including when the non-firm capacity is fully subscribed.

If a non-firm customer discontinues service, the remaining existing non-firm customers in the same

[10] Five customers.
[11] Four customers.
[12] In these instances, Hydro would need to ensure a fair allocation among customers of the excess non-firm capacity.
[13] In this circumstance, Hydro will conduct an open process prior to allocation of additional non-firm capacity among applicants. Existing non-firm customers would have the opportunity to apply to increase their non-firm capacity allocation as part of this process.

region will be provided the option to share equally in the newly available non-firm capacity. If at the conclusion of this process, non-firm capacity remains available in the region, then Hydro will offer the unused non-firm capacity available to new applicants. Hydro is reflecting the administration of entrants on the proposed non-firm rate in the terms and conditions provided with the Labrador Interconnected System Non-Firm Rate provided in Schedule 2.

2.2 Proposed Non-Firm Interconnection Requirements

Customer curtailment during time of system constraints is structured to be automated and controllable by operators in Hydro's Energy Control Centre ("ECC"). To avoid negatively impacting reliable supply of firm load, customers would be required to curtail load within ten minutes of being advised by Hydro. In the case where the customer does not manually curtail their load within ten minutes, then Hydro can automatically curtail the customer's load.

While customer curtailments would be automated to the fullest extent possible, operational procedures and protocols must be established to ensure that non-firm customer curtailments can be safely and effectively performed by ECC operators. For this reason, the total number of interruptible customers availing of non-firm service must be limited. To meet this requirement, only customers with a load of 1.5 MW or more will be considered for a non-firm energy rate option and each customer will be required to interconnect at transmission system voltages of 46 kV or higher. Requiring non-firm service to be supplied at transmission voltage ensures that the required infrastructure resources are available for reliable monitoring, operational control, and curtailment functionality.

There are currently no customers served at transmission voltage in Labrador East. Additional transmission infrastructure upgrades will be required to serve non-firm load requests; these are currently being evaluated. The existing 25 kV distribution system cannot accommodate material load growth and Hydro does not have infrastructure in place to permit remote monitoring, control, and curtailment. To reliably meet projected customer non-firm load requirements in the Happy Valley-Goose Bay area, the system needs to be upgraded, which would likely include a new terminal station and new transmission line. On the basis of preliminary estimates, these upgrades could cost in excess of $17 million. Given the magnitude of these upgrades and the high cost and time frame required to construct them, Hydro is also studying the feasibility of connecting non-firm customers at a location outside the town of Happy Valley-Goose Bay and closer to the Muskrat Falls Terminal Station. The non-firm applicants have been informed of Hydro's approach and are in support of this additional analysis.

Preliminary interconnection estimates for this system expansion option will be completed in early fall of 2022. Under Hydro's proposed non-firm service rate, the non-firm customers would be required to fund the required transmission upgrades and interconnection costs.

In Labrador West, aside from the interconnection costs to provide non-firm service, material transmission infrastructure investments such as major station or transmission line upgrades are not anticipated as necessary to enable the provision of non-firm service. However, customers would be responsible for all system upgrades required to enable remote monitoring, control, and curtailment requirements. The proposed interconnection requirements are set forth in the terms and conditions provided in Schedule 2.

2.3 Proposed Non-Firm Rate Structure

2.3.1 Jurisdiction Scan of Non-Firm Rates

In developing its proposal, Hydro requested Christensen Associates Energy Consulting ("CA Energy Consulting") to conduct a review of non-firm rates by other utilities, provided as Attachment 2. In other regulatory jurisdictions, non-firm energy is sometimes referred to as surplus or additional energy. Customers purchase surplus energy recognizing its availability may be limited and the energy may only be available during specific seasons or times of day. In other Canadian jurisdictions, four utilities sell surplus or additional energy on a non-firm basis, specifically, Manitoba Hydro, BC[14] Hydro, Hydro-Québec and NB[15] Power. Manitoba Hydro, BC Hydro and NB Power base their pricing for non-firm energy on a forecast regional export market price. For the Additional Electricity Option, Hydro Québec uses a combination of both embedded and market based costs in computing the price.[16] The jurisdictional scan revealed there is limited use of non-firm energy rates among U.S. utilities. This is likely because much of the U.S. grid is more network than radial in nature when compared with Canadian grids, reducing the U.S. need for non-firm arrangements and direct load control to ensure grid security.

[14] British Columbia ("BC").
[15] New Brunswick ("NB").
[16] Hydro Québec also has a "Rate for Cryptographic Use Applied to Blockchains". The rate is unusual as it applies to one specific type of customer and was implemented in response to direction from the Québec government. The pricing parallels the firm rate for large loads but participating customers are subject to interruptions for up to 95% of their load requirements. The rate also has an inclining block structure with a materially higher rate that applies to usage above the amount authorized.

2.3.2 Incremental Cost Pricing

Hydro is proposing to charge for the provision of non-firm energy based on the incremental/marginal costs of supply. This is consistent with the current IIC Non-Firm Rate. Hydro believes it is appropriate to incorporate marginal costs within the approach to pricing non-firm service, where marginal costs are based on the market value of energy within regional wholesale markets. The market value of exports reflects the fact that sales of non-firm energy will result in reduced energy available for export.

Hydro also applies incremental pricing for the sale of energy in excess of the monthly forecast requirements provided by Labrador Industrial customers. The Imbalance Rate on the Labrador Interconnected System applies to excess energy sold to Labrador Industrial customers;[17] the price for the Imbalance Rate is based on the forecast average monthly market price. As mentioned earlier, marginal/incremental costs are considered in pricing of non-firm energy in other Canadian jurisdictions.

Historically, the vast majority of exports have resulted from the sale of excess Recapture Energy in the New York wholesale energy market. However, with the commissioning of the Project and the construction of the Maritime Link, Hydro projects that the future value of most export sales will reflect the prices in the New England Mass Hub energy market. Therefore, Hydro proposes to compute a blend of the two forecast market prices in determining the non-firm rate. Hydro considers a weighted average of the projected price (net of delivery costs) from these markets a reasonable approach to setting a rate reflective of the incremental cost for non-firm service.

The two market sources Hydro is planning to use are the "NYISO Zone A Day-Ahead Peak Calendar-Month 5 MW Futures" and the "ISO New England Mass Hub 5 MW Peak Calendar-Month Day-Ahead LMP Futures".[18] The information for these markets is publicly available for use in rate setting. As the Project is not fully commissioned, there is uncertainty in the near-term with respect to the volume of exports that will flow to New England over the Maritime Link. Therefore, in computing the non-firm rate, Hydro proposes to use the proportion of total exports to each market from the previous calendar month to compute the price for the next month. Hydro plans to monitor its export activity on an

[17] The Labrador Industrial customers provide the energy purchases forecast to Hydro prior to the beginning of each month; purchases in excess of their monthly forecast are billed to the Labrador Industrial customers at the Imbalance Rate which is updated monthly.

[18] Hydro has historically used the New York Zone A market in setting the market block rate for Labrador Industrial customers.

ongoing basis and, in future, may propose refinements to the source of market data used to establish the non-firm rate.

2.3.3 Time Differentiation in Pricing

Hydro is also proposing that the non-firm energy rate differentiate between peak and off-peak periods based on the forecast monthly average market values for these time periods. The winter on-peak period is proposed to be 7 am to 10 pm Monday to Friday for the months of December to March and the non-winter peak period is 8 am to 10 pm for the period April to November.[19] This time of use approach will provide non-firm customers an opportunity to lower their costs by maximizing non-firm purchases during off-peak times. Separate pricing for peak and off-peak periods would also provide the opportunity for customers to limit the frequency of curtailments (as a higher curtailment frequency would be expected during peak periods) by purchasing more of their energy requirements during the off-peak period.

The determination of the frequency in which the non-firm price gets updated requires a balancing of customer rate stability with the degree of certainty desired with respect to the market value of exports. Customers want to have certainty on the price of electricity well in advance whereas the market value of exports varies by day and by hour. BC Hydro and Manitoba Hydro update their surplus price daily providing a forecast price for the next day. Manitoba Hydro updates its forecast price for surplus energy on a weekly basis, whereas the Hydro Québec price for the Additional Energy Option is updated monthly to reflect seasonal forecast differences of incremental costs.

Based on Hydro’s discussions with applicants, potential customers would rather have an annual average price to provide more certainty with respect to monthly and annual electricity costs. Hydro has concerns with the annual approach as there are material differences in market value by season and substantial price variation within seasons.[20] The use of an annual projected price could result in Hydro selling non-firm energy materially below the incremental cost/value during the winter months and above the incremental cost/value during the non-winter period. Hydro does not consider the use of annual

[19] The on-peak period is reflective of the update to the Marginal Cost Study for the Island Interconnected System dated January 18, 2022 and filed with the Board in response to TC-IC-NLH-001 as part of the regulatory process for the Electrification, Conservation and Demand Management Plan 2021–2025. For the Labrador Interconnected System Non-Firm Rate, the on- and off-peak time periods will use the Atlantic Time Zone. For the IIC Rate, the time periods will use the Newfoundland Time Zone.
[20] The forecast market value during the winter months can be in excess of three times the market value during the non-winter months.

average price to be reasonable with respect to the provision of an efficient price signal to non-firm customers and believes that it presents a substantial risk that Hydro would achieve a lower value through the sale of non-firm energy on the Labrador Interconnected System than it would if the energy was exported.

Applicants also suggested consideration of a non-firm price to be updated seasonally. Updating the price by season is preferential to annual; however, a seasonal pricing approach would create a several month delay in responding to material changes in market value. Hydro believes a reasonable balance between efficient pricing and rate stability would be achieved by updating the non-firm rate on a monthly basis. Under this approach, Hydro would access the published forecast market pricing for the subsequent month and publish the price on the 21st day of the month prior to the month for which the price will apply. Reflecting a forecast market price and publishing it in advance is also consistent with Hydro's approach with the Imbalance Rate that applies to excess energy sales to Labrador Industrial customers.[21] The Imbalance Rate reflects a forecast average market price for the subsequent month.

2.3.4 Demand Charges

Under the proposed terms and conditions of the non-firm energy rate, the sale of non-firm energy will not contribute to increased investment in generation capacity or common transmission capacity and, therefore, will not contribute to additional capacity costs to be recovered through firm customer rates. Investment in transmission, if required, to provide non-firm service to new customers will be recovered through up-front contributions from non-firm customers. While the non-firm customers will not pay explicitly for the use of the common transmission facilities system through customer rates, they will be subject to the pricing variability in the energy markets and may at times pay charges for non-firm energy in excess of the published firm energy rates. This would be expected to occur frequently in Labrador where the firm electricity rates are among the lowest in North America. Therefore, Hydro is proposing not to apply a demand charge for the use of non-firm service. This approach is consistent with the

[21] The Imbalance Rate reflects a forecast average market price for the subsequent month; it does not reflect peak and off-peak periods. However, Hydro plans to review time differentiation for this rate in the future. Discussions with the Labrador Industrial customers will be required to determine if benefits can be achieved by implementing on-peak and off-peak pricing for the Imbalance Rate.

pricing for surplus/additional energy in other Canadian jurisdictions.[22] The proposed approach will provide for increased revenue from non-firm sales to offset the estimated reduction in net exports due to those increased non-firm sales.[23]

2.3.5 Administrative Costs

Hydro has historically applied a 10% administrative overhead rate in deriving the IIC non-firm price. However, non-firm sales on the Island were not material in the past, likely because the non-firm cost per kWh was materially higher than the firm energy rate. In the future, it is expected that the non-firm rate will often be lower than the firm energy price for the Island Interconnected System, and several customers on the Labrador Interconnected System are expected to subscribe to non-firm service only. Therefore, the usage of non-firm energy is projected to be materially higher in the future and the use of a 10% loader would not be considered cost-based. Similarly, Hydro's review of other jurisdictions in Canada did not find that other utilities applied an administrative charge to their non-firm rate.

While Hydro found that an administrative loader applied to the variable energy charges may not be cost based, Hydro will be incurring administrative costs in the provision of non-firm service (e.g., billing costs, meter reading, posting the monthly price, administering curtailments, etc.). Therefore, Hydro believes it is appropriate to apply a monthly customer charge to non-firm customers. Hydro does not currently have an explicit demand charge for large general service customers on the Labrador Interconnected System. Given the administrative costs for non-firm customers should be reasonably comparable to large General Service customers on the Island Interconnected System (interval metering installed, some customers on curtailable service), Hydro proposes that a monthly Basic Customer Charge equal to that applied for Island Interconnected System General Service customers with demands of 1,000 kVA or greater should apply to non-firm customers on the Labrador Interconnected System; the Island Interconnected System Rate is currently $85.25 per month.

[22] Table 1 in the CA Energy Consulting report shows that no demand charges are applied in the non-firm incremental energy designs of BC Hydro, Manitoba Hydro, NB Power and Hydro Québec.
[23] The current Supply Cost Variance Deferral Account rules provides for the benefits of non-firm revenues generated based on the use of hydraulic generation be credited to the Supply Cost Variance Deferral Account. Non-firm revenues generated as a result of thermal generation will be applied against the supply costs incurred to provide the service.

2.3.6 Illustrative Non-Firm Energy Rate Calculation

Table 3 provides an illustrative calculation of the non-firm price for the months of February and July 2023 based upon the forecast net price[24] from exports for each month. The monthly price is calculated based for the forecast net revenues from exports reflecting a blending of the New York and New England market forecasts. For illustration purposes, Table 3 assumes 75% of exports flow to New York and 25% flow to New England for the previous calendar month.

Table 3: Illustrative Calculation of Non-Firm Energy Rate Based on Monthly Market Value

	On-Peak Cents per kWh					Off-Peak Cents per kWh				
	New York		New England		Average	New York		New England		Average
February 2023	14.8	75%	37.7	25%	20.5	9.7	75%	32.3	25%	15.4
July 2023	8.3	75%	8.7	25%	8.4	5.2	75%	5.8	25%	5.35

Table 3 illustrates that the market value of exports can vary materially by season and time of day.

Table 4 demonstrates the increase in the actual and forecast net market value of exports since 2020.

Table 4: Net Market Value of Exports

Historical and Forecast Net Market Prices		
Year	New England Mass Hub	New York Zone A
2020	1.73	2.28
2021	4.01	3.71
2022F	11.26	7.79
2023F	13.72	6.51
2024F	10.51	5.05
2025F	8.93	4.97

Table 4 shows that the market values of exports are forecast to be relatively high for the 2022–2024 time frame compared to market values for the years 2020 and 2021. This increase in price may influence the number of customers that want to avail of the non-firm service. However, a high market value

[24] New York Net Back Price = Zone A Price x Foreign Exchange Rate x Hydro Québec Energie Transmission Loss Factor. New England Net Back Price = ((((Mass Hub Price x Foreign Exchange Rate) - (Cost of New Brunswick System Operator Transmission)) x New Brunswick System Operator Transmission Loss Factor) - Cost of Nova Scotia System Operator Transmission) x Nova Scotia System Operator Transmission Loss Factor x Maritime Link Loss Factor.

would present the opportunity to create more value for customers by either exporting surplus energy or selling non-firm energy reflecting the market opportunity of exports. It is notable that the forecast average market prices are higher in the New England market and the extent to which this market price impacts the non-firm rate is dependent on the reliability of the LIL and the amount of exports that will flow over the Maritime Link.

Schedule 2 to the application provides the proposed non-firm rate sheet for the Labrador Interconnected System.

3.0 Elimination of Secondary Energy Rate on the Labrador Interconnected System

Hydro is also proposing to eliminate the Secondary Energy Rate[25] that is available for customers on the Labrador Interconnected grid engaged in fuel switching.[26] The energy delivered under the terms of this non-firm service was to be used solely for the operation of the equipment engaged in fuel switching. CFB[27] Goose Bay was the only customer on this rate and has discontinued the practice of switching from oil to electricity at times when there is surplus energy and non-firm capacity available in Labrador East. Similar to the proposed non-firm rate, Hydro could interrupt or reduce the supply of secondary energy to meet its firm energy commitments to customers.

The proposed Labrador Interconnected System Non-Firm Rate would eliminate the requirement for the Secondary Energy Rate as the proposed rate enables the sales of non-firm energy to customers but does not specifically define the end use for which the energy is available.

4.0 Update to Island Industrial Non-Firm Rate

Hydro offers its Industrial customers on the Island Interconnected System a non-firm energy rate for a customer-specific MW block which is in excess of their firm load. The energy price which applies when using load in excess of firm load is based upon Hydro’s incremental energy costs at the time of delivery, plus an administrative fee and a charge for system losses. Historically, the energy costs have typically been based on the monthly Holyrood TGS fuel cost. There is no demand charge for the use of the non-

[25] The Secondary Energy Rate was Rate 5.1L.
[26] The customer was required to purchase a minimum of 1 MW load and a maximum of 24 MW.
[27] Canadian Forces Base (“CFB”).

firm capacity made available within the contracts. Customers that avail of non-firm purchases must discontinue use of interruptible demand if requested by Hydro due to system constraints.

With the interconnection of the North American grid, the marginal energy costs for both systems should now consider the market value of exports. Continuing to charge IIC a non-firm rate based solely on fuel cost would be inconsistent with cost based pricing when fuel cost is not expected to reflect Hydro's ongoing incremental cost of supply. However, with the ongoing uncertainty on the reliability of the LIL, the proposed non-firm rate for IIC will need to continue to have the option to apply thermal fuel costs as an incremental cost in computing the non-firm rate.

Hydro is proposing to modify the non-firm component of the IIC Rate Sheet to reflect that the incremental cost of providing non-firm energy will no longer only reflect thermal generation but will reflect the market value of exports most of the time. Hydro is proposing to align the IIC Non-Firm Rate with the Labrador Interconnected System non-firm energy prices for periods when the market value of exports reflect Hydro's incremental cost of supply. Schedule 3 to this application provides the proposed revised IIC Rate Sheet.[28]

[28] Based on Hydro's review of non-firm rates in other jurisdictions, Hydro is proposing to eliminate the application of the 10% administration fee when fuel is used to supply non-firm energy for the IIC Non-Firm Rate.

Schedule 1, Attachment 1

Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System

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Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System

June 30, 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Contents

List of Appendices

1.0 Introduction

In recent years, Newfoundland and Labrador Hydro ("Hydro") has experienced load growth in Labrador, primarily due to the arrival of data centres/cryptocurrency mining sites to the region. As Hydro's Labrador Interconnected System has minimal excess capacity available to serve new customers, the Labrador Interconnected System will require substantial investment in upgrades to supply firm service to new customer load. To ensure the costs associated with these upgrades are fairly allocated, Hydro undertook the process of developing a new policy for addressing network additions on the Labrador Interconnected System ("Policy") which identifies how new customers will be treated in regards to their impact on the system and how costs will be allocated among customers for reliability, economic, transmission, and load upgrades. The Policy underwent substantial regulatory process and examination by the parties and was approved by the Board of Commissioners of Public Utilities ("Board") on March 17, 2021.[1]

In its report on Hydro's proposed Policy, the Board's consultant, The Brattle Group Inc., recommended that the Policy include a non-firm rate option whereby customers could avail of surplus energy when available but accept interruptions when the system does not have capacity to provide service. This option would require no additional common transmission capacity investment in the Labrador Interconnected System; therefore, no contribution for the provision of additional firm capacity would be required from customers availing of non-firm service. Additionally, there has been a level of customer interest in such an offering. As such, as part of the settlement agreement to the regulatory proceeding examining the Policy, Hydro agreed to conduct a review of the feasibility of adding a non-firm rate option to the Policy and file a report with the Board by mid-2021.

The purpose of this report is to provide the results of Hydro's analysis to determine the technical feasibility of offering a non-firm rate option for customers of the Labrador Interconnected System and to identify other considerations which would require further evaluation should Hydro proceed with implementation of a non-firm rate option. The approach taken to determine the feasibility of creating a non-firm rate option in Labrador was based on a near-term analysis of the current transmission infrastructure (including approved upgrades) and current energy supply available from Churchill Falls for use in Labrador. Depending upon the changes in system costs if material expansion occurs on the

[1] Board Order No. P.U. 7(2021).

Labrador Interconnected System, the pricing of non-firm service would be need to be reviewed to ensure the rate structure is reasonable and promotes efficient usage by participating customers.

2.0 Applicant Load Requests

Since its approval, Hydro has been advancing the work required to implement the Policy and work through the outstanding requests for power in Labrador. As a first step, proponents were asked to submit applications indicating their load and location requirements. Table 1 summarizes the applications received as of June 1, 2021. Hydro is reviewing these applications and completing the assessments necessary to determine next steps and inform customers of potential costs. Hydro believes that a substantial portion of the requests identified in Table 1 may be withdrawn once customers are made aware of the costs associated with fulfilling their requests; however, requests that do materialize into firm customer requirements and changes to the configuration of the Labrador Interconnected System may impact the amount of non-firm load that can be made available on the Labrador Interconnected System.

Table 1: Summary of Applications Received as of June 1, 2021

	Load (MW)	Number of Applications
Labrador West	551	15
Labrador Central	1,141	6
Labrador East	6,227	31
Labrador Interconnected System Total	**7,919**	**52**

3.0 Technical Feasibility of Non-Firm Offering

To determine the amount of energy that could be made available on a non-firm basis, there are two primary considerations—the capacity of the transmission system to deliver the energy to customers and the amount of energy available for supply. Hydro undertook two pieces of analysis to support its assessment of the availability of a potential non-firm offering. The first was a review of the transmission system to quantify how much load could reliably be added to the system during each season of the year. For preliminary planning purposes, the analysis was based on a premise that a maximum of 50 interruptions would provide an acceptable limit for customers and for reliable system operation. The second analysis was to quantify the amount of surplus energy available in the region. If applicants that are interested in non-firm service would not be willing to accept 50 interruptions, Hydro would need to modify the amount of non-firm service that can be made available to reflect what would be acceptable to the applicants.

3.1 Transmission Capacity

A technical analysis of the available transmission capacity in Labrador was conducted to determine the available capacity for connecting non-firm loads and the expected number of interruptions at different load levels. Analysis was completed for each season to identify the number of interruptions a non-firm customer would expect to experience at different load levels. Table 2 identifies the quantity of non-firm load that could be added to each of the regions, by season, while maintaining a maximum planned number of interruptions to fewer than 50 occurrences. Hydro's technical analysis is attached as Appendix A.

Table 2: Maximum Non-Firm Load for Labrador East and Labrador West (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Labrador East	28	43	58	38
Labrador West	20	50	50	50

The non-firm capacity available is indicative of the seasonal nature of the load requirements on the Labrador Interconnected System. Higher winter load requirements reduce what can be made available on a non-firm basis during the winter months. If the iron ore mines increased their load requirements during the non-winter months closer to their Power on Order (which they fully utilize during the winter), the amount of non-firm capacity that can currently be made available during the non-winter months would need to be reduced materially.

As indicated earlier, the amount of MW that can be made available will be subject to discussions with the applicants on what will be acceptable to them from an operations perspective.

3.2 Available Generation

Presently, Hydro has two contracts with Churchill Falls to supply power to customers on the Labrador Interconnected System. First, Churchill Falls sells up to 225 MW (TwinCo[2] Block) to Hydro for sale to Labrador West customers, with first priority given to industrial customers in Labrador West. Second,

[2] Twin Falls Power Corporation Limited ("TwinCo").

Churchill Falls sells 300 MW to Hydro for use in the province (Recapture Block) with no limitations on location of use. There is currently more Recapture Energy available than what is currently needed to serve Hydro's existing customers in Labrador. Hydro currently sells the surplus to Nalcor Energy Marketing for export. Table 3 summarizes the average surplus Recapture Energy available by season.

Table 3: Average Surplus Recapture Energy (GWh)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Surplus Energy	248	356	524	439

For preliminary planning purposes, available surplus Recapture Energy may be approximated to be 60 MW over peak. The average available surplus recapture capacity over the past three years is provided in Table 4. This capacity could be used to serve non-firm load in Labrador rather than be exported. As indicated, the ability to support incremental load is restricted by transmission system limitations. Under the current load requirements for the Labrador Interconnected System, even if the available transmission capacity were fully utilized at a 100% capacity factor, surplus Recapture Energy would not be exhausted.

Table 4: Average Surplus Recapture Capacity (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Surplus Capacity	115	161	237	201

3.3 Total Non-Firm Supply Available

As there is more energy available than transmission capacity, the transmission system remains the constraining factor for adding any new load in Labrador. Based on the available transmission capacity, the quantities of non-firm capacity that could be available in each of Labrador West and Labrador East (subject to customer review) are shown in Table 5.

Table 5: Total Available Non-Firm Capacity (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Labrador East	28	43	58	38
Labrador West	20	50	50	50
Total	**48**	**93**	**108**	**88**

4.0 Additional Considerations

There are practical and operational considerations that need to be addressed to offer a non-firm energy product that is fair to customers and that does not impact the reliability of the system. These considerations are noted in the following sections.

4.1 Practical Limitations

In accepting a non-firm energy product, customers must be able to accept that the delivery or receipt of the energy may be interrupted at any time without liability on Hydro or the customer. Non-firm customers must understand that increased usage by other customers on the Labrador Interconnected System with firm service will be prioritized and the amount of non-firm service may decline over time.

As per the technical review provided in Appendix A, the following guidelines are recommended with respect to customer curtailment in the provision of non-firm service:

- Customer curtailment must be automated and controllable by operators in Hydro’s Energy Control Centre (“ECC”). The cost of infrastructure to ensure reliable operation and curtailment would be borne by the customer.
- While customer curtailments would be automated to the fullest extent possible, operational procedures and protocols must be established to ensure that manual interruption of all required customers can be safely and effectively performed by ECC operators. On this basis, the total number of interruptible customers must be limited. The exact number of interruptible customers that could be served would be subject to an operational review.
- To ensure reliable system operation, only customers with a load of 1.5 MW or more should be considered for a non-firm energy rate option. To ensure reliable operation from Hydro’s ECC, customers would be required to interconnect at transmission system voltages of 46 kV or higher, which would ensure that the required infrastructure and resources are available for reliable monitoring, operational control, and curtailment functionality. To ensure fairness and to enable more than one customer to avail of this service, a maximum non-firm capacity should be established based on the degree of interest in non-firm service.

- In the event that there is more customer demand for a non-firm rate option than Hydro has capacity to serve, a fair and transparent process must be developed to determine how customers will be selected.

4.2 Non-Firm Service Terms and Conditions

Hydro believes the following process would be reasonable to apply to applicants willing to proceed with non-firm service.

The group of applicants interested in proceeding with non-firm service would fund a system impact study for use in finalizing the amount of non-firm capacity that will be made available.

After receiving the results of the system impact study, Hydro would finalize the proposed terms of non-firm service rate with the applicants and apply to the Board for approval of the terms and conditions and the pricing structure. Anticipated provisions of a non-firm service rate would include:

- Non-Firm Offering: The product is non-firm energy, meaning delivery or receipt of the energy may be interrupted at any time without liability on Hydro or the customer. Standby generation would not be used to ensure continuity of service to non-firm customers.
- Interconnection Costs: Customer is required to pay the full cost of interconnection in advance of Hydro starting any work related to connecting the customer.
- Service Size: Minimum customer service size to be 1.5 MW.
- Notice to Curtail and Automatic Curtailment: Customer would be required to curtail load within ten minutes of being advised by Hydro. In the case where the customer does not manually curtail their load within ten minutes then Hydro can automatically curtail the customer’s load. Any equipment, software, and resources required to remotely monitor and enable automatic curtailment at both Hydro’s facilities and the customer’s facilities will be paid for fully by the customer.
- Service at Transmission Voltage: To allow real-time monitoring of the reliability of the Labrador Interconnected System, non-firm energy customers would be required to interconnect at transmission system voltages of 46 kV or higher. Non-firm customers must provide their own transformation, breaker, protection, communications equipment, etc. at their site as per normal firm service customers.

- Security Deposit: The customer would be required to provide reasonable security prior to Hydro connecting service, usually in the form of two months equivalent bills. The security deposit will be returned when the customer has established two consecutive years of good credit history with Hydro.
- Term of Agreement: The term of the Non-Firm Power Service Agreement would be for a minimum of three years. Revision to the terms of the non-firm service would be subject to approval of the Board.

5.0 Rate and Regulatory Considerations

To determine a just and reasonable rate for a non-firm service offering on the Labrador Interconnected System, Hydro has considered generally accepted sound public utility practice and regulatory principles.

5.1 Non-Firm Rates in Canadian Jurisdictions

Based on a review of other jurisdictions in Canada, non-firm rates appear to be of two types: i) the provision of non-firm capacity in excess of the customer's firm load requirements based on the incremental cost of supply and ii) the payment of a credit to customers to reduce their available firm load.

Hydro offers its industrial customers on the Island Interconnected System a non-firm energy rate for a customer-specific MW block which is in excess of their firm load. The energy price which applies when using load in excess of firm load is based upon Hydro's incremental energy costs at the time of delivery, plus an administrative fee and a charge for system losses. Historically, the energy costs have typically been based on the monthly Holyrood Thermal Generating Station fuel cost. In recent years, there has been no demand charge on the island for the use of the non-firm demand made available within the contracts. Customers that avail of non-firm purchases must discontinue use of interruptible demand if requested by Hydro due to system constraints.

Hydro offers up to 5 MW of interruptible load to Labrador Industrial Customers. This enables these customers to use 5 MW above their firm demand without impacting their annual Power on Order. Because there have historically been capacity constraints on the Labrador Interconnected System, these customers pay the approved demand charge for interruptible demand. The price these customers pay for non-firm energy is typically based on the second block energy rate, which is a market-based rate. As these customers primarily use their interruptible demand during the winter season, the second block energy rate or the imbalance energy rate would normally apply. The second block energy rate is set annually based on a forecast market-based rate. The imbalance energy rate applies to energy usage above the forecast provided by the customer and is based on the average market price in the month the energy is used. The Labrador Industrial Customers must also discontinue the use of interruptible load when requested by Hydro.

In New Brunswick, customers can avail of interruptible energy in excess of the demand reserved for the customer if energy is available and can be provided with available resources over and above the utility's other firm commitments. The rate charged for interruptible energy is based on NB Power's incremental cost, plus an adder of 0.9 cents per kWh on peak and 0.3 cents per kWh off peak. In substance, this rate offering is similar to Hydro's non-firm energy rate on the Island Interconnected System.

In British Columbia, industrial customers[3] can avail of "Freshet Energy" during spring runoff periods where excess energy is available on the system. Customers pay their standard transmission demand rate; however, they can avail of Freshet Energy at a price equal to the greater of the hourly day-ahead market price or $0, plus an adder of $3/MWh.[4]

In Quebec, industrial customers[5] are offered bill credits for interruptions at the request of the utility. Depending on the number and duration of interruptions, customers can receive both fixed (demand) and variable (energy) credits against their published industrial rates.[6] In substance, this program is similar to Hydro's Capacity Assistance Program on the Island Interconnected System.

In Nova Scotia, large industrial customers[7] who agree to be interrupted qualify for a demand charge discount $3.43 per month per kVA for billed interruptible demand against published industrial rates.[8]

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[3] Customers served at voltages of 60 kV and greater (BC Hydro Rate 1823).
[4] BC Hydro Rate 1892.
[5] Rate L applies to an annual contract whose contract power is 5,000 kW or more and which is principally for an industrial activity.
[6] "Interruptible Electricity Options for Rate L customers," Hydro Québec, <https://www.hydroquebec.com/business/customer-space/rates/interruptible-electricity-options-large-power-customers.html>.
[7] Customers on the Large Industrial Tariff with a minimum regular billing demand of 2,000 kVA at 90% Power Factor.
[8] "Interruptible Rider to the Large Industrial Tariff, Nova Scotia Power, <https://www.nspower.ca/about-us/electricity/rates-tariffs/interruptible-rider>.

In Hydro's view, the provision of a non-firm rate in Labrador should reflect a similar pricing approach that applies to Hydro's approach to non-firm service for additional load requested by its industrial customers in the province. The provision of a demand-based credit is generally applied to reduce the charge as a result of providing a reduced quality of service to customers that already have firm service. In the case where firm service cannot be provided, Hydro believes it is appropriate to emphasize marginal costs in considering the pricing approach for non-firm service. The provision of non-firm service on the Labrador Interconnected System will result in reduced energy available for exports. The provision of non-firm service is also accompanied by administrative costs to Hydro to ensure non-firm capacity use does not impact the provision of firm service. Hydro's pricing approach for non-firm service is conceptually similar to the approach used in New Brunswick and British Columbia.

5.2 Potential Rate Structure

Based on the foregoing, Hydro believes the following rate design approach would be appropriate for non-firm service on the Labrador Interconnected System.

Table 6: Potential Labrador Interconnected System Non-Firm Rate Structure

Rate	Details
Demand Charge	Demand charge based on transmission costs[9] (non-ratcheted)
Energy Charge	Greater of market-based energy charge[10] or incremental energy supply cost[11] (updated monthly) Plus: an administrative and variable operating and maintenance charge (10.0%)

As the non-firm customers would use the transmission system, Hydro believes it would be appropriate for the customers to pay a transmission demand charge based on the average embedded cost of demand. This is currently $1.08 per kW on the Labrador Interconnected System. As this service is non-

[9] Hydro is not including a standby generation demand charge as non-firm customers would be subject to interruption; therefore, standby generation would not be used to ensure continuity of service.
[10] This approach is similar to the imbalance rate applicable to Labrador Industrial customers, which is also a market based rate. For July 2021, the imbalance rate is $31.46 per MWh.
[11] If the incremental supply costs are used in determining the non-firm rate, the incremental supply cost would be adjusted to reflect Labrador Interconnected System losses.

firm, the rate would apply to the maximum monthly demand and would not apply to the maximum annual demand as is the case for firm demand.

The proposed energy rate should be based upon the greater of Hydro's forecast marginal energy cost reflecting the opportunity cost of lost export sales[12] or Hydro's incremental cost of supplying the non-firm energy. This approach ensures that Hydro can cover its cost of serving non-firm customers if Recapture Energy is fully utilized and other more expensive supply sources are required. An administration fee of 10% will recover Hydro's cost of offering this rate and is consistent with current practice on the Island Interconnected System. Hydro will finalize the details of the proposed rate design if its discussions with customers result in Hydro proposing a non-firm rate.

6.0 Conclusion

Hydro believes that a non-firm rate option may be feasible for a limited number of customers in Labrador. However, further discussions are required to finalize what can be made available and attributes that would be practical to implement for both Hydro and the potential customers. Hydro will proceed with engaging customers who have expressed an interest and move forward to determine if the applicants are interested in proceeding with development of a rate option based on the parameters described in this report. Hydro welcomes feedback from the Board and parties on its proposed approach.

[12] This currently reflects the New York Market for Labrador sales.

Appendix A

TP-TN-101

Labrador West and Labrador East Customer Curtailment/Interruptible Assessment

newfoundland labrador hydro
a nalcor energy company

Doc #: TP-TN-101
Issue Date: 2021/04/06
Document Type: Technical Note

TP-TN-101

Labrador West and Labrador East Customer Curtailment/Interruptible Assessment

Purpose

The purpose of this technical note is to assess the opportunities available for connecting interruptible/curtailable load at Labrador East and Labrador West. The assessment includes a review of projected loads in Labrador East and Labrador West from 2021 to 2026, with the objective to determine the available capacity for connecting firm and interruptible industrial loads and expected number of interruptions at different load levels.

Overview

LABRADOR EAST

The construction of a 6 km transmission line extension from L1302 to the Muskrat Falls Terminal Station 2 (“L1303”), the expansion of the Muskrat Falls Terminal Station 2, and the upgrades to the Happy Valley Terminal Station will increase the available capacity in Labrador East to 104 MW during the winter, spring and fall months and 88.9 MW during the summer months. The ten-year P90 peak forecast[1] for Labrador East is shown in Table 1.

Table 1: Labrador East Load Forecast (MW)

Year	Baseline Peak
2021	79.70
2022	80.40
2023	81.00
2024	81.60
2025	81.90
2026	82.20
2027	82.90
2028	83.60
2029	84.30
2030	84.90

[1] Labrador Interconnected System Long-Term Load Forecast at January 2021 – transmittal.

LABRADOR WEST

Under existing system conditions with WTS Synchronous Condenser #3 ("SC3") in service, the total peak capacity of Labrador West is 385 MW during the winter, spring, and fall months and 310 MW during the summer months. The expected peak forecasts for Labrador West for the study period were derived from the baseline peak load forecast[2] which includes the loads for Newfoundland and Labrador Hydro ("Hydro") Rural, Iron Ore Company of Canada ("IOC") and Tacora Resources Inc. ("Tacora"). The ten-year P90 load forecast for Labrador West is shown in Table 2.

Table 2: Labrador West Load Forecast (MW)

Year	Baseline Peak
2021	377.3
2022	377.6
2023	377.9
2024	378.3
2025	378.6
2026	378.8
2027	379.0
2028	379.2
2029	379.3
2030	379.5

OPERATIONAL CONSIDERATIONS

The following operational considerations are defined for the purpose of this investigation:

INTERRUPTIONS DUE TO PLANNED AND FORCED OUTAGES

In addition to the planned interruptions due to system loading conditions quantified in this analysis, interruptible customers would also be subject to interruptions due to annual maintenance outages and forced outages. Contractual provisions are therefore recommended to accommodate potential capacity limitations during such events or due to force majeure.

Operational Management of Customer Interruption

The number of interruptions is dependent on the size of the load blocks and the curtailment required.

[2] Labrador Interconnected System Long-Term Load Forecast at January 2021 – transmittal, adjusted to reflect the operation of SC3

The smaller the size of independent load blocks, the greater the flexibility an operator will have to rotate interruptions. That being said, the number of independent load blocks must be limited due to the complexity of operation.

To ensure reliable operation, the following premises have been established with respect to customer interruption:

- Customer interruption must be automated and controllable by operators in Hydro's Energy Control Center ("ECC"). The cost of infrastructure to ensure reliable operation and interruption must be borne by the interruptible customer.

- While customer interruptions would be automated to the fullest extent possible, operational procedures and protocols must be established to ensure that manual interruption of all required customers can be safely and effectively performed by ECC operators in case of emergency. On this basis, the total number of interruptible customers must be limited. The exact number of interruptible customers that could be served would be subject to an operational review.

  As described in the following sections, a seasonal review of each system has been performed and a determination has been made on the acceptable number customer interruptions in each case. For the purposes of this preliminary investigation, if the number of interruptions is found to be in the order if 50 occurrences or more, it is deemed to be unacceptable due to the complexity of protocols and challenges associated with reliable operation.

Industrial Customer Entitlements

Contractual arrangements with IOC and Tacora are such that each of these customers has a entitlement to a Power on Order capacity plus an interruptible capacity of 5 MW each. As a result of capacity allocations, no firm capacity is available in western Labrador. For the purposes of this analysis, capacity available for new interruptible arrangements is calculated on the basis of historic load profiles. The opportunity for such arrangements could be rescinded if industrial customers were to develop projects or modify production profiles that resulted in off-peak load increases within their entitled capacities.

Firm Capacity Availability

The establishment of the Muskrat Falls–Happy Valley Interconnection will result in an increase in available firm capacity in eastern Labrador. The allocation of this firm capacity will be determined by Hydro as part of the ongoing analysis being performed in support of the implementation of the Network Addition Policy. It is recommended that firm capacity be allocated in advance of interruptible capacity.

ANALYSIS

LABRADOR EAST

Labrador East Load Profile:

The projected hourly load profiles for years 2021 to 2026 were extrapolated from historical (i.e., 2018, 2019 and 2020) load profiles. The expected annual load profile for 2026 (assuming no new incremental firm customers) is shown in Figure 1. As shown in Figure 1, there is a reduction in the thermal rating of L1303 and consequently the available capacity in Labrador East in the summer months.

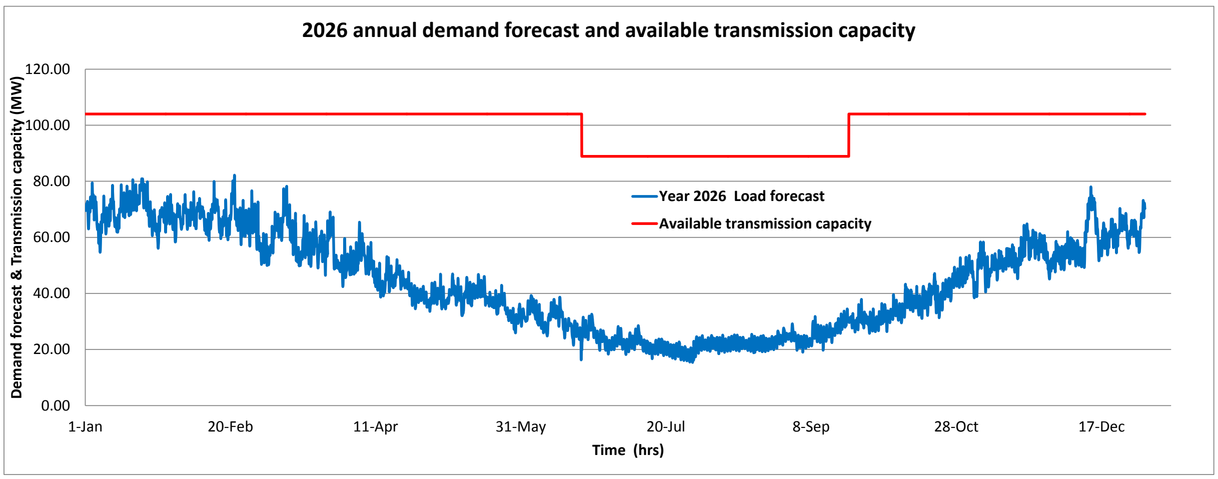

Figure 1: Labrador East Projected Load Profile for 2026 and Available Transmission Capacity

Annual Interruptible Load Analysis[3]

The expected probability and number of interruptions for ranges of load increments in 2026 is shown in Table 3.

[3] Expected curtailments are based on expected load and capacity of the transmission infrastructure and do include annual maintenance and forced outages.

Table 3: Probability and Number of Expected Load Interruptions for Ranges of Load Addition at Labrador East

Additional Load (MW)	Probability of Load Interruption (%)	Number of Interruption
18-23	0.02	1
23-28	0.97	32
28-33	4.93	163
33-38	13.01	430
38-43	21.82	721
43-48	28.89	955
48-53	37.66	1,245
53-58	45.42	1,502
58-63	55.98	1,851
63-68	80.11	2,649
68-73	94.05	3,110
73-78	99.27	3,283
78-83	99.95	3,305
83-88	100.00	3,307

As shown in Table 3, there is a minimum risk of interruption with the connection of up to 23 MW of load. The risk of interruption increases slightly with the connection of an additional 5 MW, however the overall risk of interruption remains below 1%. Therefore, additional 5 MW (i.e., a total of 28 MW) of load can also be accommodated; however, it might be subjected to partial or complete interruption in supply during the winter months.

Seasonal Interruptible Load Analysis

Electricity demand varies through the year; consequently the size of interruptible load that can be accommodated varies as well. Table 4 to Table 7 shows the number of interruptions expected for winter, spring, summer, and fall 2026. [4]

Expected Interruptions during Winter Months

As shown in Table 4, a maximum of 23 MW of firm load can be connected during the winter months. An addition 5 MW (i.e., a total of 28 MW) of load can be connected; however, the additional load will be subjected to manageable interruptions. The addition of loads greater than 28 MW will result in large number of interruptions and unacceptable operational complexity.

[4] Expected interruptions are based on expected load and capacity of the transmission infrastructure and do not include annual maintenance and forced outages.

Table 4: Expected Number of Interruptions per Additional Load Connection to Labrador East in Winter

Additional Load (MW)	Number of Expected Interruptions in Winter 2026
18-23	1
23-28	31
28-33	148

Expected Interruptions during Spring Months:

As shown in Table 5, a maximum of 33 MW of firm load can be connected in spring months. Additional 10 MW (i.e., a total of 43 MW) interruptible loads can be connected without significantly increasing the complexity of scheduling load interruptions. Conversely, connecting a cumulative load greater 43 MW will result in large number of interruptions and increase operational complexity.

Table 5: Expected Number of Interruptions per Additional Load Connection to Labrador East in Spring

Additional Load (MW)	Number of Interruption in Spring 2016
< 33	0
33-38	2
38-43	19
43-48	58

Expected Interruptions during Summer Months:

A maximum of 53 MW of firm load can be connected in summer months with no expected number of interruptions as shown in Table 6. An additional 5 MW (i.e. a total of 58 MW) interruptible load can be connected without significantly increasing the complexities of scheduling interruptions. The addition of a cumulative load greater 58 MW is expected to result in large number of interruptions and unacceptable operational complexities.

Table 6: Expected Number of Interruptions per Additional Load Connection to Labrador East in Summer

Additional Load (MW)	Number of Interruption in Summer 2026
< 53	0
53-58	12
58-63	129

Expected Interruptions during Fall Months:

A maximum of 28 MW firm lo ads can be connected in fall months. An additional 10 MW (i.e., a total of 38 MW) manageable interruptible load can be connected.

Table 7: Expected Number of Interruptions per Additional Load Connection to Labrador East in Fall

Additional Load (MW)	Number of Interruption in Fall 2026
18-23	0
23-28	1
28-33	15
33-38	27
38-43	72

LABRADOR WEST

Labrador West Load Profile:

The projected hourly load profiles for years 2021–2026 were extrapolated from historical (i.e., 2018, 2019, and 2020) load profiles. The expected annual load profile for 2026 is shown in Figure 2. The available transmission capacity in the winter, spring, and fall months is 385 MW. The transmission capacity reduces to 310 MW in summer months due to thermal rating of 230 kV transmission lines L23 and L24. As stated above, IOC and Tacora each have an interruptible entitlement of 5 MW. A total of 10 MW must therefore be deducted from available interruptible capacity.

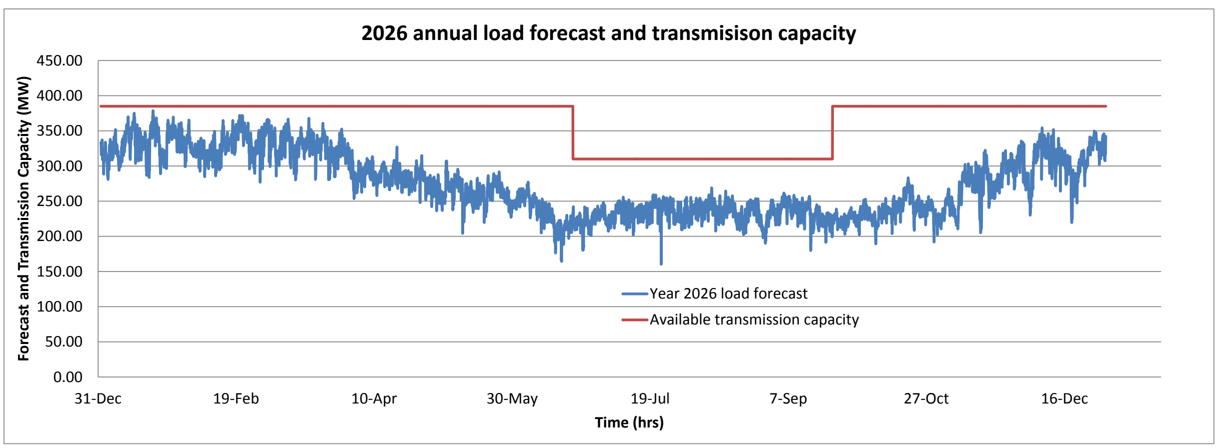

Figure 2: Labrador West projected Load Profile for 2026 and Available Transmission Capacity

Annual Interruptible Load Analysis[5]

The expected probability and number of interruptions for different levels of load additions in year 2026 is shown in Table 8. As indicated, the 10 MW total interruptible entitlement of IOC and Tacora can be accommodated with a low risk of interruptions. An additional 10 MW of interruptible load could also be served with a reasonable number of interruptions.

[5] Expected curtailment is based on expected load and capacity of the transmission infrastructure and does not include annual maintenance and forced outages.

Table 8: Probability and Number of Expected Load Interruption for Ranges of Load Addition at Labrador West

Additional Load (MW)	Probability of Curtailment	Number of Interruption
0-10	0.02	1
10-20	0.78	26
20-30	2.91	96
30-40	6.70	222
40-50	12.35	408
50-60	21.51	711
60-70	34.57	1,143
70-80	46.22	1,528
80-90	56.60	1,872
90-100	64.76	2,142
100-110	71.55	2,366
110-120	76.68	2,536
120-130	80.82	2,673
130-140	85.49	2,827
140-150	90.17	2,982
150-160	94.65	3,130
160-170	98.20	3,247
170-180	99.43	3,288
180-190	99.74	3,298
190-200	99.92	3,304
200- 210	99.95	3,305
210 - 220	100.00	3,307
220 - 230	100.00	3,307
230 - 240	100.00	3,307

Labrador West Seasonal Interruptible Load Analysis[6]

The expected number of interruptions for winter, spring, summer, and fall is shown in Table 9 to Table 12.

Expected Interruptions during Winter Months

As shown in Table 9, the IOC and Tacora 10 MW interruptible entitlement and an additional 10 MW of interruptible load can be accommodated. The addition of loads greater than 20 MW will result in too large a number of interruptions to be operationally viable.

[6] Expected interruptions are based on expected load and capacity of the transmission infrastructure and do include annual maintenance and forced outages.

Table 9: Expected Number of Interruptions per Additional Load Connection to Labrador West in Winter

Additional Load (MW)	Number of Interruption in Winter 2026
0-10	1
10-20	19
20-30	79
30-40	191
40-50	329

Expected Interruptions during Spring Months:

As shown in Table 10, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the spring. This includes the interruptible entitlements for IOC and Tacora.

Table 10: Expected Number of Interruptions per Additional Load Connection to Labrador West in Spring

Additional Load (MW)	Number of Interruption in Spring 2026
<30	0
30-40	6
40-50	20
50-60	45

Expected Interruptions during Summer Months:

As shown in Table 11, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the summer.

Table 11: Expected Number of Interruptions per Additional Load Connection to Labrador West in Summer

Additional Load (MW)	Number of Interruption in Summer 2026
< 40	0
40-50	2
50-60	75
60-70	270

Expected Interruptions during Fall Months:

As shown in Table 12, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the summer.

Table 12: Expected Number of Interruptions per Additional Load Connection to Labrador West in Fall

Additional Load (MW)	Number of Interruption in Fall 2026
< 30	0
30-40	3
40-50	16
50-60	43
60-70	88

CONCLUSION

The amount of interruptible loads that can be connected to Labrador East and Labrador West is summarized in Table 13.

Table 13: Interruptible Load Limits in Labrador West and Labrador East

	Annual	Winter	Spring	Summer	Fall
Labrador East	28	28	43	58	38
Labrador West[7]	20	20	50	50	50

This analysis excludes capacity limitations from planned and unplanned maintenance because they are common to all scenarios, hence, contractually provisions are recommended to accommodate such events.

As stated above, the opportunity to provide interruptible service is subject to review to ensure safe and reliable operation. Opportunities for the addition of interruptible load must be made in consideration of industrial customer entitlements in western Labrador and potential firm load allocations in eastern Labrador.

[7] Labrador West totals include a combined 10 MW interruptible capacity allocation entitled to IOC and Tacora.

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0	B. Odetayo	Initial Release	2021/05/14
1	B. Odetayo	Addition of 10 MW total interruptible entitlement of IOC and Tacora	2021/05/20

Document Control

Regarding Transmission Planning documents: The electronic version of this document is the CONTROLLED version. Please check the Transmission Planning Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

Schedule 1, Attachment 2

Review and Analysis of Non-Firm Rate Design Alternatives

newfoundland labrador hydro

Review and Analysis of Non-Firm Rate Design Alternatives

for

Newfoundland and Labrador Hydro

by

Christensen Associates Energy Consulting, LLC
Madison, Wisconsin

March 16, 2022

Table of Contents

Review and Analysis of
Non-Firm Rate Design Alternatives

for

Newfoundland and Labrador Hydro

by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

March 16, 2022

1. INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) wishes to update the non-firm pricing aspects of its Island Industrial rate (IIR). The company would also like to explore non-firm rate design alternatives more generally, as the Labrador Industrial System (LIS), with its current concerns regarding transmission constraints, might benefit in the future from the availability of non-firm pricing rate designs.[1]

The current IIR non-firm design is in need of renovation for a number of reasons. First, in the past, non-firm pricing was based on the incremental generation cost of the existing sources of incremental generation services. The potential sources of incremental generation have changed with the interconnection of Muskrat Falls and the completion of the Maritime Link with the Eastern Interconnection. At a minimum, the non-firm rate would need to reflect these new sources.

Second, the position of the utility regarding net supply has continued to evolve, with increased potential for incremental sales at times when capacity is abundant. Third, customer needs and preferences appear to be changing. There is reportedly increased interest in market-based energy pricing, based on wholesale market prices for energy available via mainland interconnection, and coupled with the anticipated rise in embedded cost-based generation price levels for firm load. Additionally, changing customer load profiles in some cases, combined with ongoing customer-site generation capability, suggest the value of non-firm pricing that is compatible with possible standby service needed by some customers.

Fourth, the ways that non-firm service can be offered have changed over recent years, with increased emphasis on market-based pricing, indicating that a review of design alternatives would be beneficial.

Additionally, the LIS is an increasingly likely candidate for non-firm service in that cryptocurrency mining and other energy-intensive industries are considering Labrador (along with many other jurisdictions) for potential future growth. Absent significant new investment in

[1] Labrador energy pricing is determined separately from Hydro rates, with the exception of transmission cost recovery. However, the Province may wish to consider non-firm energy pricing designs similar in nature to those eventually chosen for the Island.

the Labrador transmission system, the path to accepting applications for such service appears to be via non-firm generation service offerings. Therefore, non-firm designs within the NL Hydro system as a whole might benefit from the application of similar design considerations, even though the circumstances on the Island and in Labrador might differ in terms of transmission grid structure and capacity.

This report begins by reviewing non-firm rate designs and then describes the current non-firm rate design serving the Island Industrial customers. The next section documents current non-firm pricing practices in Canada and the U.S. Subsequently, the report outlines rate designs that might suit the future needs of Hydro and its customers.

1. NON-FIRM RATE DESIGNS

Vertically integrated utilities that offer non-firm power do so using two main rate structures. First, some utilities offer interruptible/curtailable (I/C) designs in which customers receive a demand charge discount in return for making a portion of their capacity non-firm. For these designs, the utility sets out the terms of interruption[2] – time of year when interruption can occur, maximum frequency and duration of interruption, and advance notice of an upcoming interruption period required of the utility – along with the penalties for failure to interrupt in a timely manner or to the required extent. Penalties are typically severe, consisting of demand charge discount reduction up to suspension from participation in the rider.

Second, utilities sometimes offer non-firm service where energy consumption is incremental to a contract level of demand. The utility notifies the customer when this service is not available and there are consequences for continuing to consume above the contract level at times when incremental energy is not available. Demand charges are based on the contract level and the incremental energy price differs from the standard tariff energy price, being based typically on some measure of the utility's marginal cost.

While apparently different in structure, these two designs strive to achieve similar objectives: the ability to obtain load relief from customers at times of reduced system reserves in return for reduced pricing. I/C designs invite customers to volunteer load for curtailment, while incremental rates make energy available subject to the utility's ability to obtain and deliver it. Customers provide load relief by not consuming non-firm power when denied access by the utility.

In practice, under I/C rates, the utility pledges to limit requests for load relief from the customer to a finite number of curtailment calls, a predetermined number of hours of curtailment per call, and a limited number of hours of curtailment in total throughout the year. Under incremental rates, no such pledge is made, but customers subscribe to incremental pricing under the implicit pledge of frequent but not continuous availability. In the past, I/C

[2] This report uses the terms interruption and curtailment synonymously. At one point, interruption meant reduction of firm power to zero while curtailment meant reduction to a non-zero firm power level. Such a distinction no longer appears to apply.

rates have based their pricing on embedded cost principles: forecasted curtailment calls result in a forecast of demand- and energy-related costs avoided, and these savings translate into a demand charge discount and, on occasion, a reduced energy price. (The reduction reflects reduced expected sales at times of peak cost.)

In contrast to contractual agreements to curtail load, incremental energy rates have tended to rely on measures of incremental or marginal cost, perhaps averaged over expected periods of availability or sometimes disaggregated into seasonal or time-of-use (TOU) prices. Currently, the apparent gap between I/C designs and incremental energy designs is bridged by designs that use market-based pricing to secure load relief as a replacement for penalty pricing. Rates such as critical-peak pricing, peak-time rebate, and, in an all-hours environment, real-time pricing represent such designs. Instead of an embedded cost-based energy price, hours of curtailment can feature market-based pricing, sometimes with a buy-through provision that permits the customer to purchase load above their contract level at a high energy price that reflects the scarcity of reserves.

2. THE ISLAND INDUSTRIAL RATE

The rate that currently serves Hydro's Island Industrial customers has both firm and non-firm elements. An Industrial customer obtains firm power under the terms of their Industrial Service Agreement, within which a contract demand level, referred to as Power on Order, sets a maximum level of firm power service. This demand level, or actual demand if greater, is the basis for a demand charge. A flat nonseasonal energy price is applied to actual consumption in the billing period to yield an energy charge. Additionally, the customer pays a per-kWh Rate Stabilization Plan Adjustment and Conservation and Demand Management charge. Lastly, there is a customer-specific Specifically Assigned Charge covering the cost of plant assigned to a given customer.

Customers have access to non-firm energy, when available, via a non-firm service provision. Since the energy is non-firm, there is assumed to be no demand-related cost to recover from these incremental sales, as no incremental grid investment is deemed necessary. The energy price is based on the marginal cost of the fuel for the generator that happens to be at the margin when incremental energy is available. Three types of generators are nominally available to meet this need: Holyrood, gas turbines, and diesels. The prices are fixed and do not vary by season or time of day. (Specific identification of the marginal unit performs the service of time variation in pricing, as needed.) Again, the Industrial Service Agreement determines the customer's terms of use.

Additionally, Hydro engages with customers who have site generation to provide additional supply at times when system reserves are very low. Pricing and the terms of service are established in customers' Capacity Assistance Agreements. These agreements act as extensions of interruption or non-firm power agreements, providing load relief in addition to the relief provided by the suspension of non-firm power availability.

Looking forward, the completion of the interconnection with the mainland and the arrival of power from Labrador complicates the identification of the marginal generation unit. With variation across seasons and in level of exports, the marginal cost of energy and reserves is based more on market values rather than the marginal cost of a specific generator, making pricing via tariff sheet problematic.

Additionally, Hydro has lately undertaken considerable research into marginal costs, developing detailed forecasts of level and pattern, along with analyses of variability over time. The utility has thus developed the ability to quote non-firm energy prices at relatively short notice to customers, assuring them of the availability of Hydro's "best price" for incremental energy. This potential price transparency also serves the utility and regulators by making it possible to tie the price of incremental energy closely to its forecasted marginal cost, ensuring minimization of cross subsidy concerns.

Viewed in terms of familiar criteria for a successful rate design, the current IIR achieves much of what Hydro needs.[3] The rate is simple, treats industrial customers equally, has the ability to recover embedded costs fully, and can thus avoid cross-subsidization with other rate classes. However, its marginal pricing looking forward is not efficient. That is, it does not tell customers accurately the cost to the utility of producing an additional kWh, since the actual or forecasted marginal costs of non-firm power can no longer be reflected in the tariff prices. A revised design will need to improve on price efficiency and avoid reduced ability to meet other rate design criteria.

Hydro recognizes an additional criterion for a successful industrial rate: provide non-firm service that keeps obligation to serve within the bounds of generation and delivery capability. Hydro's approach is to offer incremental energy only when available and subject to the terms of the customer's industrial service agreement. Hydro uses this approach in preference to an I/C tariff, which offers firm service unless a curtailment call is made. The effect is quite similar, but a customer on an I/C tariff may have different expectations as to availability of energy. As well, in most jurisdictions, a customer may opt out of I/C service and convert all load to firm power. Under incremental non-firm service, a customer seeking increased firm service must adjust its contract demand subject to utility approval, which may not be granted until assurance of delivery capability can be made.

3. INDUSTRY PRACTICE

3.1 Canadian Designs

Table 1 presents rate designs of Canadian utilities that offer non-firm incremental pricing.
BC Hydro offers to its transmission-level customers one permanent incremental rate and one pilot rate with a similar structure. These customers' base tariff has an inclining block energy price, with the block boundary based on a customer-specific contractual amount of energy, the

[3] The standard reference is Bonbright, Danielson, and Kamerschen, *Principles of Public Utility Rates*, c. 1988, Public Utility Reports, Inc., p. 381*ff*.

Customer Baseline Load (CBL).[4] A typical customer's CBL is set at 90% of normal usage (based on historical consumption), so that the customer's marginal price for expanded consumption is usually the tail block price. The current energy prices are 4.507¢/kWh for block 1 and 10.095¢/kWh for block 2, resulting in a signal to conserve energy in amounts up to 10% of expected consumption.

However, with marginal costs well below the tail block price in recent years, and with ample run-of-river hydro resources in the period May to July, BC Hydro has used its Freshet rate to sell incremental non-firm energy when available. The energy price is determined by Mid-Columbia wholesale prices, with day-ahead on-peak and off-peak pricing. There is no demand charge incremental to the demand charge of the base rate, with billed demand being the lesser of actual demand during the peak period ("High Load Hours") and "Reference Demand", which is the average of May, June, and July recorded HLH demands in 2015, the last period before Freshet service was initiated. (The intent is to bill for demand based on "normal" peak usage in the absence of the Freshet rate.) BC Hydro's newly introduced pilot Incremental Energy rate is similar in structure, but applicable to the full year, whenever BC Hydro makes non-firm energy available. This pilot runs through March 31, 2024.[5]

An interesting feature of these rates is that they require the customer to increase consumption overall and not just when the Mid-C-based on-peak or off-peak energy prices are low. The utility uses a net-to-gross consumption calculation to reward customers who have overall incremental consumption while not rewarding those who merely shift consumption between high-priced and low-priced periods.[6]

NB Power offers an incremental energy option as part of its Large Industrial rate. The Surplus Energy Charge provision is available to customers willing to commit to a contract for three years. These customers have access to non-firm power that is curtailable with ten minutes' notice, but purchases of at least 2 MW are required. A customer who installs on-site generation can convert equivalent capacity to non-firm status. The surplus energy price is TOU in form and based upon the utility's incremental costs. Prices are quoted on a day-ahead basis, although a week-ahead forecast is also provided.

(Please see next page.)

[4] There is a time-of-use option with a similar structure and an optional tariff with no CBL and no blocking as well.
[5] See rate schedules 1892 for the Freshet rate, and 1893 for the Incremental Energy rate.
[6] Each month's (peak) net-to-gross ratio is the total (peak) period's incremental energy divided by the sum over the (peak) period's hours in which the hourly energy exceeds the baseline level. Similar algebra applies in the off-peak (Low Load Hours) period. The more consistently the customer expands consumption above baseline, the higher the net-to-gross ratio.

Table 1
Non-Firm Incremental Energy Designs at Canadian Utilities

	BC Hydro		Manitoba Hydro	Hydro-Quebec	NB Power	NL Hydro
Rate/Rider/Program	Rider	Rider - pilot	Program	Rider	Rider	Rate
Identifier	Freshet Energy - RS 1892	Incremental Energy - RS 1893	Surplus Energy	Additional Electricity Option	Surplus Energy	Island Industrial Non-Firm
Eligible/Applicable	Transmission Svc	Transmission Svc	Industrial, Commercial	Large Customers (>5MW)	Large Industrial w/ incr. of 2 MW	Transmission svc with firm energy contract
Length of commitment	season	to 3/31/2024		1 billing period	3 years	firm service
Demand price	none	none	none for commodity	none	none	firm demand price
Energy price	day-ahead TOU based on Mid-C prices, applied using net-to-gross measure of incremental energy	day-ahead TOU based on Mid-C prices, applied using net-to-gross measure of incremental energy	varies weekly, based on spot market	winter: wtd avg of avoided cost, heritage price; summer: heritage price	day-ahead TOU based on incremental cost	depends on thermal generator on the margin
Contract level	usage from 2015 or before using rider; TOU periods, by month	pre-pilot usage; TOU periods by month	contract demand	Reference Power (recent peak demand, contract)	Contract demand	Firm rate demand

Manitoba Hydro offers both a Surplus Energy Program to commercial and industrial customers and a Curtailable Rate Program to large industrial customers only. The Surplus Energy Program offers week-ahead pricing on load incremental to contract demand on a non-firm basis in circumstances where long periods of interruption can occur. Energy pricing is market-based, and the evaluation of energy increments eligible for this pricing is more direct than at BC Hydro in that there is no net-to-gross computation. Usage in excess of contract demand at any time is priced as incremental.

Hydro-Quebec also offers a combination of interruptible riders and an Additional Electricity Option, and customers can participate in both. Hydro-Quebec's Rate L for industrial customers features an Optimization Charge that penalizes customers for exceeding 110% of their contract demands during the winter period. The penalty is a large demand charge applied on each day in which an excess occurs. Customers can immediately increase their contract demand but cannot reduce it for one year. This places a high cost on incremental consumption beyond a 10% increase.

The Additional Electricity Option affords customers the opportunity, by prior arrangement, to increase energy consumption on a non-firm basis for flexible periods of service but of at least one billing period. The energy price for this additional energy is established monthly, seven days before the beginning of the calendar month. This price is seasonal in methodology of calculation. In winter, the additional energy price is a weighted average of Hydro-Quebec's winter avoided cost and its current heritage energy price. In summer, avoided cost serves as the basis for pricing.[7] The weight on avoided cost is the share of hours in which the utility plans to make short-term market-based energy purchases in the winter period to support delivery of the additional energy.

This approach is less market-based than the other structures described above due to the longer advance notice and period of price fixity, and because the winter price is a weighted average of a market-based and embedded cost-based price, which results in the retail price being less closely connected to market price than elsewhere.

Canadian utilities also offer I/C rates. Table 2 presents these non-firm rate designs. All energy is sold at a firm service price unless the utility notifies customers of an interruption or curtailment period. The customer who volunteers for I/C service receives a discount on the portion of their peak demand that the customer elects to make non-firm.

Three utilities – Manitoba Hydro, Hydro-Quebec, and NB Power – are present in both tables. At Manitoba Hydro, curtailable service is available only to customers who can reduce load on short notice by at least 5 MW. The curtailable program offers customers a menu of alternatives in which greater exposure in terms of frequency and duration is offset by increased advance notice and larger price discounts.

[7] The winter period is December 1 through March 31. The summer period is the remainder of the year.

Table 2
Interruptible/Curtailable Rate Designs at Canadian Utilities

	Manitoba Hydro	Hydro-Quebec	Hydro-Quebec	NB Power	Nova Scotia Power	Newfoundland Power
Rate/Rider/Program	Program	Rider	Rate	Rider	Rider	Rider
Eligible/Applicable	5 MW reduction	Large, 3 MW	Medium, Large; >50kW	Large Industrial	Large Industrial	300 kW reduction
Length of commitment	one year	one year	5 yr; annual contract	one year; closed to new	five years	six months
Curtailments	three options	two options				
Portion of year	Full year (4/1-3/31)		Full year (4/1-3/31)	full year	Full year, but billing ratchet is Dec.-Feb.	December - March
Admissible hours	all hours	all winter	all	all hours		8a - 9p
Max hours	A: 63.75; R: 106.25; E: 720; AE: 783.75; RE: 826.25	Option 1:100 Option 2: 50	300, some transitional customers have fewer		30% of month; 15% of year	100
Max number	A: 15; R: 25; E: 3; AE: 18; RE: 28	Option 1: 2 per day, 20 per winter; Option 2, 1 per day, 10 per winter	NA			
Duration of each	A, R: 4.25 hr; E: 10 days	4-5 hours	NA	up to 10 hours	up to 16 hours/day	up to 6 hours
Advance notice	A, R: 5 min; E: 48 hr	2 hours weekdays; day-ahead weekends	2 hours	NA	10 minutes	at least 1 hour
Contract quantity						
FPL	X					X
Load reduction	X	X	X	X	X	X
Demand charge reduction	Reference Discount	Effective Fixed Credit	none			Curtailment Credit
Months of credit	full year	Winter		full year	full year	May is payment month; credit earned Dec.-Mar.
Energy price/credit	Reserve Discount	Effective Variable Credit	Standard tariff	Interruptible Energy Charge		
Penalties	discount reduction; direct load control; disconnection; termination	discount reduction; additional charges	Excess energy @15¢/kWh; during curtailment @ 51¢/kWh	discount reduction; termination	discount reduction; additional charges	discount reduction
Buythrough provision	none	none	see above	none	none	none

Hydro-Quebec offers two options with varying frequency per day and per winter period, and applicable to the winter period only. The demand charge discount is larger for the option that permits more interruptions, and there is an energy credit as well. There are demand charge penalties for exceeding contract demand, with the penalties applying to the sum of 15-minute period overruns. Because there is such a stringent limit on overrunning contract power, Hydro-Quebec includes demand forgiveness in post-interruption recovery periods, provided that the recovery occurs in off-peak hours.

Perhaps the most unusual non-firm rate in Canada is Hydro-Quebec's "Rate for Cryptographic Use Applied to Blockchains". The rate is unusual in that it is open to one specific type of customer only: those who are engaged in cryptocurrency "mining", i.e., performing data intensive calculations that add to the customer's store of cryptocurrency, or "banking", i.e., performing cryptocurrency record keeping. The utility's approach to service for this group involves setting out a maximum amount of available consumption and then soliciting bids for service. Those accorded service make a five-year commitment under annual contracts.

Service under this rate is non-firm, with a maximum number of curtailable hours but without detail as to when these hours might occur. Advance notice is just two hours, perhaps reflecting the responsiveness of these customers to curtailment calls. Pricing is somewhat unusual as well, relative to other I/C rates or riders. There is no discount for non-firm service relative to the base rates that customers would otherwise use for service. In addition, there are premium prices for exceeding the authorized demand level, or for exceeding the curtailed level in curtailment periods (which is just 5% of recorded past peak demand).[8]

The resulting structure makes the rate look more like an incremental energy rate, in which the base level of consumption is zero. Customers are priced comparably to other (firm service) customers of similar size, except for the requirement to curtail, whose pricing implications are confined to service above the contract level. The Optimization Charge is replaced by premium energy pricing and the power of curtailment requirements, reinforced by the high energy charge.

NB Power also has a curtailable service option, but it is closed to new load. For curtailable customers with an established contract demand, the utility offers a demand charge discount for curtailable demand.

Nova Scotia Power offers a demand charge discount on demand in excess of contract demand. In addition, total energy consumption is priced at a slight discount (about 4 mills/kWh). This discount presumably reflects the reduction in energy-related costs arising from the customer's forecasted reduced consumption at times of high energy cost when interruption is likely.

[8] The energy prices as of April 1, 2022 were: 3.596¢/kWh for authorized consumption, 15.590¢/kWh for consumption in normal periods for consumption above the authorized level, and 51.967¢/kWh for exceeding the allowed level in periods of curtailment.

Newfoundland Power provides a curtailable service option for its large business customers, applicable to the winter period, in peak hours. The utility's two curtailable service options illustrate the two main traditional ways of recording load reduction. The first option requires the customer, when called, to reduce demand by a prespecified amount, while the second requires reduction of demand to a Firm Demand level. (The first of these requires an agreed-upon a measure of load reduction. However, this approach offers a firmer guarantee to the utility of load reduction when needed. A customer served under the second option might be close to their firm demand level at the time of the curtailment call and offer relatively little load relief as a result.) Unlike other utilities with multiple curtailment options, Newfoundland Power does not differentiate its options with regard to limits on frequency or duration of curtailment events. In both cases, customers are promised advance notice of one hour.

Hydro itself does not offer curtailable service in the form of a rate or rider, but has a similar facility in the previously mentioned Capacity Assistance Agreements with customers having site generation capability. These agreements can include not only provision of customer site generation services at times of low system reserves but interruption of some site consumption as well.

It should be noted that none of the Canadian I/C rate structures include a buy-through option, in which a price (other than a penalty price) is applicable to load exceeding the contract or firm service level.

Viewed in combination, the incremental/surplus energy and interruptible/curtailable designs provide Canadian utilities with ways to price non-firm energy tailored to their existing tariff structures and the needs of customers. As noted, some utilities make use of both designs.

3.2 U.S. Designs

A review of U.S. utilities that are prominent in serving industrial customers revealed a preponderance of I/C rate designs and limited use of incremental non-firm energy. The review also includes two instances of real-time pricing for large customers, which is worth including despite the fact that it constitutes firm service, because it illustrates the use of time-varying energy pricing to secure load relief, a strategy which incremental energy designs utilize as well. Tables 3A and 3B present the results for I/C rate designs.

Table 3A provides documentation on the first group of utilities. (The ordering of utilities is alphabetical.) These utilities are each members of an ISO or RTO. AEP Ohio belongs within PJM, while DTE Energy and Entergy Louisiana are members of MISO. Membership influences I/C rate design both with regard to curtailment terms and in pricing. For example, AEP Ohio's design ties curtailments to PJM curtailment events and limits advance notice to 30 minutes.

Entergy Louisiana's three options are experimental and tie the energy price to pricing from MISO. Otherwise, there is variation in the utility's programs in terms of frequency and duration of interruption, and in degree of advance notice. One of these options is a relatively conventional structure with 3 hours' advance notice and is open to a customer capable of

curtailing at least 150 kW. The other two are intended for larger or more flexible customers capable of curtailing 1,000 kW and having new load of at least 500 kW. Each of these has additional options in terms of hours of exposure, but one is related to a call option and thus has the financial value of load relief explicitly monetized.
Additionally, one of Entergy Louisiana's rate designs has a buy-through provision. Despite close ties to ISO/RTO pricing, there appear to be no other provisions for price-based discretion regarding the degree of compliance with a curtailment call.

The rate designs found in Table 3A all happen to be of the contracted load reduction variety, while those in Table 3B are not, perhaps indicating that tight relations with an ISO/RTO induces the need to structure rates so that load relief is directly measured and priced. In each case, penalties for failure to curtail are substantial.

Table 3B reveals the influence of ISO/RTO rules as well, with similar influence on call frequency and duration in several cases. However, there is still a broad range of terms across utilities. For some of the market-based designs, commitments are relatively brief, while long-term commitments in the traditional manner are still required for other rate designs. Likewise, the range of advance notice of curtailment is from 15 minutes (for a mandatory curtailment plan at PG&E) to two hours.

(Please see next page.)

Table 3A
Interruptible/Curtailable Rate Designs at U.S. Utilities

	AEP - Ohio	DTE Electric Company			Entergy Louisiana LLC		
Rate/Rider/Program	Interruptible Power	Interruptible General Service	Interruptible Supply	Interruptible Supply	Experimental Energy Reduction Service Rider	Experimental Market Value Energy Reduction: Call Option Service	Experimental Market Value Energy Reduction: Energy Service
Eligible/Applicable	Can curtail 1,000 kW	No Off-Peak Customers	Primary customers, >50 kW	Primary Supply Rate and Manufacturing Supply customers, >50,000 kW	>500 kW; ability to curtail 150 kW	New firm load >500 kW; ability to curtail 1,000 kW	New firm load >500 kW; ability to curtail 1,000 kW
Length of commitment	1 year	3-day notice	5 years	2 years			
Curtailments							
Portion of year		full year	full year			All Year	
Admissible hours		All hours	All hours	All hours	5PM-9PM Oct-Apr; 2PM-6PM May-Sept		
Max hours							
Max number	PJM Curtailment					June, May, Sept: 15/month; July, August: 20/month	
Duration of each					4	8	
Advance notice	30 min	1 hour	1 hour	10 minutes; but typically 1 hour	3 hours	Option A: 20 hours; Option B: 2 hours	Option A: 12-22 hours; Option B: 2 hours
Contract quantity							
FPL	X						
Load reduction		X	X	X	min 90%*Curtailable Demand	X	X
Energy price/credit					Day-Ahead Price	June, May, Sept: $100/MWh; July, August: $150/MWh	
Penalties	Refund all rate discounts from previous 12 months; after two failures, removal from program	$10 per excess kW	$10 per excess kW	$10 per excess kW		[5 * Penalty Demand * Call Option Premium] + [Penalty Demand * Call Option Energy Price]	5 * curtailment price * (Actual Demand - Firm Demand)
Buythrough provision					X		

Table 3B
Interruptible/Curtailable Rate Designs at U.S. Utilities

	Indiana Public Service	MidAmerican Energy Co	Niagara Mohawk Power Corp.		Northern States Power Co - Wisconsin	Pacific Gas & Electric Co.		
Rate/Rider/Program	Industrial Service	Curtailment Service	Emergency Demand Response Program via Voluntary Load Curtailment	Emergency Demand Response Program via On-Site Generatoin	Peak Controlled Time-of-Day General Service	Base Interruptible Program	Binding Mandatory Curtailment Plan	Scheduled Load Reduction Program
Eligible/Applicable	10,000 kW; meet requirements of MISO LMR	Can curtail 250 kW; have previously curtailed 100 kW	Can curtail 100 kW	Can provide 100 kW	Can curtail 50 kW	>100 kW; can curtail 100 kW		> 100 kW
Length of commitment	5 years for Industrial service; Quarterly contract for MISO Pricing		5 days' written notice	5 days' written notice	3 years	1 year	1 year	November cancellation for following year
Curtailments								
Portion of year								June through Sept
Admissible hours					9am-9pm			CAISO Peak Period
Max hours					150 hours	180 hrs/yr		
Max number	MISO Curtailment	5 MISO directed per year; 6 temperature-induced per year; 16 total per year	The Company shall only call upon the Customer to curtail usage when requested to do so by the NYISO	The Company shall only call upon the Customer to curtail usage when requested to do so by the NYISO		1/day; 10/month	Called by CAISO	3/week
Duration of each		6	No less than 4 hours	No less than 4 hours	2 to 12 hours	6 hrs		4 hrs
Advance notice	2 hours	If MISO directed: 6 hr notification of possibility; 30 min notification of need. If Company directed: 2 hrs	1 hour	1 hour	1 hour	30 min	15 min	
Contract quantity								
FPL		X			X	X	X	X
Load reduction								
Energy price/credit	$/kWh Day Ahead MISO LMP							10 cents/kWh
Penalties	liable for any charges and/or penalties from any governmental agency for failure to comply with a MISO Curtailment.	part or all of summer curtailment credit; must reimburse at MISO price			$16.50 per excess kW	Excess Energy Charge at $6.00/kWh; $8.40/kWh for re-test; de-enrollment	Excess Energy Charge at $6.00/kWh; de-enrollment	
Buythrough provision								

Two utilities in the review, Georgia Power and Oklahoma Gas & Electric, depart from the I/C format common to the others. Table 3C records their structures. Both designs are variants of two-part real-time pricing and are not, strictly speaking, non-firm rates. Both consist of a standard tariff applied to a customer baseline load consisting of a year of hourly consumption and monthly peak demand values that collectively represent the customer's normal usage. Departures from this baseline are priced at a marginal energy price including both energy and reserves costs, plus a margin premium.

Both of these designs also allow options for curtail ability. The customer nominates some of their baseline demand as non-firm and receives a demand credit for the difference between the CBL demand and the firm demand level. Oklahoma G&E customers also receive a performance credit when the energy price exceeds the day-ahead RTP price. (Curtailment notice can be 1 or 4 hours ahead of the curtailment period.) The effect of curtailability is to create a non-firm feature that is capable of attracting additional load reduction and that can be used to require load reductions in extreme conditions while retaining market-based pricing in all hours.

Table 3C
Firm Power Analogs of Non-Firm Rate Designs at U.S. Utilities

	Georgia Power Company	**Oklahoma Gas & Electric Co**
Rate/Rider/Program	RTP-DA	Day-Ahead Pricing
Eligible/Applicable	Commercial and Industrial Customers >250 kW	Most non-Residential Customers
Length of commitment	5 years	30 days' notice
Contract Quantity	CBL: hourly loads plus demand amounts	CBL: hourly loads plus demand amounts
Applicable Pricing	customer's base tariff	customer's base tariff
Pricing of Incremental Load	Day-ahead hourly pricing	Day-ahead hourly pricing
Interruptible Option	DPEC rider: demand credit on difference between CBL demand and Firm Demand Level of DPEC	Load Reduction Program: demand subscription credit and premium energy price; for performance credit; buy-through
Other rate option	RTP-HA (Hour-Ahead) for customers > 5MW	tried and dropped week-ahead pricing
Financial Options	Price Protection Products - Contract for Differences at avg RTP price fcst	

Georgia Power also offers an hour-ahead RTP option for very large and price responsive customers. Oklahoma G&E once had a week-ahead option but terminated it due to lack of customer interest. As well, Georgia Power offers a financial option called "Price Protection Products" in the form of a contract for differences: the customer buys an addition to their CBL for a selected period of time at a fixed price based on forecasted average RTP prices for the period. This feature allows temporary conversion of load exposed to price variation to firm pricing, with the firm price being based on market prices rather than embedded cost-based pricing.

These rates are instructive in that they retain the concept of a contract level of usage with separate pricing for increments and decrements of load. Unlike the rates previously reviewed, they are symmetrical in both structure and pricing for load increases and reductions from contract level, and reflect the cost to the utility either incurred or avoided by the customer's behavior. The day-ahead pricing structure, also found in some I/C and incremental rates, serves to improve pricing accuracy relative to after-the-fact marginal cost when compared with posted tariff prices. These rates are offered in a context of meshed networks and large customer numbers, which offers the utility some degree of predictable demand response at times of low reserves, based on the ability to attract significant and diverse customers to the rate.

The review of U.S. utility tariffs reveals that they rely less than Canadian utilities upon non-firm incremental energy rates and prefer I/C rate designs, while also securing load relief from firm-load pricing with dynamic pricing based on short-notice price quotes. The I/C designs, especially in the presence of ISO/RTO membership, appear to conform more explicitly than Canadian designs to pricing practices of wholesale markets. Marginal cost-based pricing in the U.S. tends toward short-notice price delivery and tailors curtailment call rules to the provisions of the ISO/RTO and their reserve positions.

4. NON-FIRM RATE DESIGN ALTERNATIVES

The rate design alternatives currently in use throughout North America provide examples of the three types of rate designs that Hydro may wish to consider: 1) incremental energy; 2) interruptible/curtailable; and 3) two-part dynamic pricing with an I/C provision. All options would make use of market-based pricing for energy. These design alternatives can be applied in both the update of the Island Industrial Rate, but also in the introduction of non-firm pricing in Labrador, should the approach be deemed to be beneficial. In the latter case, the presence of greater likelihood of periodic transmission constraints enhances the value of a non-firm design, at least in responding to applications for new load, whether from potential new customers or from existing customers with new uses for electricity (perhaps under the impetus of electrification stimuli).

Designs in the two regions need not be identical, especially given the differences in customers and transmission circumstances, but having similar pricing methodologies for incremental load would result in customers being offered incremental energy at comparable prices. For Hydro, it would prove valuable to be able to defend consistent pricing methods in regulatory applications, as well.

4.1 Incremental Energy

Hydro's current rate is of the incremental energy variety. The rate offers the customers and the utility the advantages of familiarity and simplicity of structure, despite the complication of increasing the price variability based on Hydro's marginal cost. The utility's recent upgrade in its ability to estimate hourly marginal costs of energy and reserves offers a market-based improvement on the existing design that is readily recognizable to customers.

This design is used elsewhere in Canada and with a variety of pricing/notice approaches. Based on their examples, Hydro can choose from either TOU or hourly pricing and week-ahead, day-ahead, or even hour-ahead advance notice. Customer preference and utility capability would help to establish a preferred design. If customers are price sensitive and energy is a significant share of their costs, then day-ahead hourly pricing would offer them significantly more benefits from price response than would week-ahead notice, and would offer Hydro more significant load relief than would a TOU price or longer advance notice. (Note that advance notice of availability of *non-firm* power might be a separate parameter, especially if there is a possibility that generation or transmission conditions would require short-notice warnings on non-availability.)

4.2 Interruptible/Curtailable Service

An I/C rate structure offers price stability but limits the introduction of market-based pricing to relatively brief intervals when curtailments are called, unless the base tariff is market-priced. While widely used in the U.S. and Canada, these rates are not as explicitly directed at making incremental energy priced at market available in most hours. However, the curtailability feature is being used with other market-based firm energy products, so I/C features might be of interest to Hydro should it be desirable to attempt to secure load reductions from contract levels at short notice.

4.3 Two-Part Dynamic Pricing

Two-part dynamic pricing rates such as real-time pricing have been in use in the U.S. for thirty years and have a proven record of price response. The design is close to the current Hydro IIR design in the sense that there is a contract amount of load beyond which a marginal cost-based price applies. The design is conceptually stronger in that the marginal price applies to load increases above and reductions below contract level. The price signal in hours of low reserves encourages customers to reduce load below the firm contract level if the price exceeds the marginal value of load to the customer. Simply put, the design signals both energy abundance by low prices and energy shortfall by high prices.

This design works best with day-ahead hourly pricing, since hourly price variation permits customers to work around periods of high pricing with greater flexibility. Day-ahead hourly pricing also sends signals at varying price levels, which may elicit a corresponding varying magnitude of price response by customers. Both features provide an improvement over a rigid TOU format.

This design is more complex than the current rate structure. Each customer must have a contractual customer baseline load consisting of demand and energy values reflecting normal usage, rather than just a contract demand. The utility must be able to price and bill on the basis of hourly loads, and customers must have some degree of price responsiveness. However, there is solid North American precedent for the design.

If Hydro is interested in this design for its incremental pricing capability but concerned about its firm service feature, the utility may want to explore an option or requirement for I/C limits. Incremental load above a contract demand level (rather than the CBL's hourly energy values) could simply be made non-firm, like the current rate. Customers could nominate a contract demand lower than CBL if they wished, in return for a demand discount of the sort found at Oklahoma Gas & Electric. Violation of the contract demand ceiling could result in loss of the demand discount or more serious penalties. However, the high energy price of the curtailment call period would likely be a sufficient deterrent for price responsive customers.

The Two-Part Dynamic Pricing rate design recovers Hydro's embedded costs, as embodied in the firm power features of the current rate, but recovers these costs fully on CBL load. The design also offers price efficiency, with prices always close to the utility's marginal cost, and secures price response below the level of contract demand, enhancing load relief potential. As well, the design uses prices that would likely be compatible with a standby design, where market prices would be used to cover the incremental costs of low load factor customers with large incremental needs, possibly emerging at short notice.

Schedule 2

Labrador Interconnected System Non-Firm Rate Sheet

RATE NO. 5.1L
NON-FIRM ENERGY

Availability

For service to Customers on the Labrador Interconnected System who purchase a minimum of 1.5 MW load, who provide their own transformer and who are delivered power at transmission voltage and subject to interruption/curtailment. Hydro shall supply non-firm energy to the Customer at such times and to the extent that Hydro has electricity available in excess of the amount it requires to meet the firm service requirements of its customers. Hydro will not utilize standby generation to supply non-firm energy. Hydro may also interrupt or curtail the supply of non-firm energy at its sole discretion to deal with system constraints.

Rate

Basic Customer Charge.. $85.25 per month

Energy Charges

Energy charges shall be the greater of:

(i) The energy charge applicable to Rate No. 2.4L – General Service 1,000 KVA and Over provided in Hydro's Schedule of Rates. Rules and Regulations; and

(ii) The applicable On-Peak Energy Rate or Off-Peak Energy Rate

The following formula shall apply to calculate the On-Peak Energy Rate and Off-Peak Energy Rate:

On-Peak Energy Rate:

The non-firm energy charge for the on-peak period for the calendar month shall be calculated monthly based on the weighted average of:

(i) the settlement price for NYISO Zone A Day-Ahead Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees; and

(ii) the settlement price for ISO New England Mass Hub 5 MW Peak Calendar-Month Day-Ahead LMP Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees.

Off-Peak Energy Rate

The non-firm energy charge for the off-peak period for the calendar month shall be calculated monthly based on the weighted average of:

(i) the settlement price for NYISO Zone A Day-Ahead Off-Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees; and

(ii) the settlement price for ISO New England Mass Hub Day-Ahead Off-Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees.

The weightings applied to each market price to calculate the on-peak and off peak energy charges will reflect the percentage of kWh exports sold (i.e., including exports from regulated and non-regulated Hydro) based on each market for the previous calendar month.

Peak and Off-Peak Periods

The winter on-peak period is proposed to be 7 am to 10 pm Monday to Friday for the months of December to March and the non-winter peak period is 8 am to 10 pm for the period April to November. The off-peak period will include all other hours.

Terms and Conditions

1. The product is non-firm energy, meaning delivery or receipt of the energy may be interrupted at any time to deal with system constraints. Standby generation will not be used to ensure continuity of service to non-firm customers.

2. The Customer will be required to interconnect at transmission system voltages of 46 kV or higher.

3. Applicants interested in proceeding with non-firm service will fund a system impact study for use in finalizing the amount of non-firm capacity that can be made available.

4. The Customer is required to fund the cost of interconnection in advance of Hydro providing service.

5. The Customer curtailment process must be automated and controllable by operators in Hydro's Energy Control Centre ("ECC"). Operational procedures and protocols must be established to ensure that interruption of non-firm customers can be safely and effectively performed by ECC operators.

6. The Customer must be capable of curtailing load within ten minutes of being advised by Hydro. In the case where the Customer does not comply with a curtailment request, Hydro can automatically interrupt supply to the Customer.

7. Any equipment, software, and resources required to remotely monitor and enable automatic curtailment at both Hydro's facilities and the Customer's facilities will be funded by the Customer.

8. The Customer will be required to provide reasonable security prior to Hydro connecting service, usually in the form of two months equivalent bills. The security deposit will be returned when the Customer has established two consecutive years of good credit history with Hydro.

9. Hydro will inform the Customer of the Non-firm energy charge on the first business day following the 21st day of the month preceding the month for which the rate is being set.

10. The Customer must supply and own the transformer supplying the customer.

11. Customer-owned equipment required for interconnection must meet Hydro's service standards.

12. The rate is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 46 kV or higher. For customers metered at the low side of the transformer, meter readings shall be increased by 1.5% for each transformation between the meter and the transmission voltage.

13. Hydro reserves the right to have a separate service agreement with the Customer to provide clarity on issues that may not be specifically set out in the Terms and Conditions.

14. If the Customer's power factor is below 90%, the Customer shall upon written notice by Hydro provide, at the Customer's expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

15. For the purpose of allocation and monitoring the use of non-firm capacity, Hydro will maintain separate regions for Labrador East and Labrador West.

16. If a non-firm customer discontinues service, the remaining existing non-firm customers in the same region will be provided the option to share equally in the newly available non-firm capacity. If at the conclusion of this process, non-firm capacity remains available in the region, Hydro can offer the available non-firm capacity available to new applicants.

17. When Hydro determines that the full non-firm capacity is utilized in a region, Hydro will not add additional non-firm customers unless additional transmission investments result in additional non-firm capacity becoming available in that region. In this circumstance, Hydro will conduct an open process prior to allocation of additional non-firm capacity among applicants. Existing non-firm customers would have the opportunity to apply to increase their non-firm capacity allocation as part of this process.

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

Schedule 3

Island Industrial Customer Rate Sheets

INDUSTRIAL – FIRM

Availability

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Base Rate*

Demand Charge

The rate for Firm Power, as defined and set out in the Industrial Service Agreements, shall be $10.73 per kilowatt (kW) per month of billing demand.

Firm Energy Charge

Base Rate..@ 4.428¢ per kWh

RSP Adjustment

Current Plan ....@ 1.060¢ per kWh
Current Plan Mitigation Adjustment.......@ (0.675)¢ per kWh
Current Plan Total..................................@ 0.385¢ per kWh

Total RSP Adjustment – All kilowatt-hours...@ 0.385¢ per kWh

CDM Cost Recovery Adjustment…………………………………………………………………………..@ 0.014¢ per kWh

Specifically Assigned Charges

The table below contains the additional annual specifically assigned charges for customer plant in service that is specifically assigned to the Customer.

	Annual Amount
Corner Brook Pulp and Paper Limited	$13,311
Braya Renewable Fuels (Newfoundland) GP Inc.	$107,678
Teck Resources Limited	$51,789
Vale	$145,352

*Subject to RSP Adjustments and CDM Cost Recovery Adjustment

RSP Adjustments refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

The CDM Cost Recovery Adjustment is updated annually to provide recovery over a seven-year period of costs charged annually to the Conservation and Demand Management (CDM) Cost Deferral Account.

Adjustment for Losses

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year shall be applied.

General

Details regarding the conditions of Service are outlined in the Industrial Service Agreements.

This rate schedule does not include the Harmonized Sales Tax (HST) that applies to electricity bills.

INDUSTRIAL – NON-FIRM

Availability

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate

Non-Firm Energy Charge: Non-Thermal Generation Source (¢ per kWh)

Hydro will inform the Customer of the Non-firm energy charge on the first business day following the 21st day of the month preceding the month for which the rate is being set.[]

Energy charges shall be the greater of:

(i) The energy charge applicable to Rate No. 2.4L – General Service 1,000 KVA and Over provided in Hydro's Schedule of Rates. Rules and Regulations; and

(ii) The applicable On-Peak Energy Rate or Off-Peak Energy Rate

The following formula shall apply to calculate the On-Peak Energy Rate and Off-Peak Energy Rate:

On-Peak Energy Rate:

The non-firm energy charge for the on-peak period for the calendar month shall be calculated monthly based on the weighted average of:

(i) the settlement price for NYISO Zone A Day-Ahead Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees; and

(ii) the settlement price for ISO New England Mass Hub 5 MW Peak Calendar-Month Day-Ahead LMP Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees.

Off-Peak Energy Rate

The non-firm energy charge for the off-peak period for the calendar month shall be calculated monthly based on the weighted average of:

(i) the settlement price for NYISO Zone A Day-Ahead Off-Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees; and

(ii) the settlement price for ISO New England Mass Hub Day-Ahead Off-Peak Calendar-Month 5 MW Futures after the end of trading on the nineteenth day of the previous month, converted to Canadian dollars using the exchange rate of the same day, and adjusted for losses and other market fees.

The weightings applied to each market price to calculate the on-peak and off-peak energy charges will reflect the percentage of kWh exports sold (i.e., including exports from regulated and non-regulated Hydro) based on each market for the previous calendar month.

Peak and Off-Peak Periods

The winter on-peak period is proposed to be 7 am to 10 pm Monday to Friday for the months of December to March and the non-winter peak period is 8 am to 10 pm for the period April to November. The off-peak period will include all other hours.

Non-Firm Energy Charge: Thermal Generation Source (¢ per kWh)

The following formula shall apply to calculate the Non-Firm Energy rate:

$$\{(A \div B) \times (1 \div (1 - C))\} \times 100$$

A = the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used

B = the conversion factor for the source used (kWh/bbl)

C = the average system losses on the Island Interconnected grid for the last five years ending in 2016 (3.34%).

The energy sources and associated conversion factors are:

1) Holyrood, using No. 6 fuel with a conversion factor of 583 kWh/bbl

2) Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl

3) Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl

Adjustment for Losses for Thermal Generation Source

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year shall be applied.

General

Details regarding the conditions of Service are outlined in the Industrial Service Agreements.

This rate schedule does not include the Harmonized Sales Tax (HST) that applies to electricity bills.

INDUSTRIAL – WHEELING

Availability

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy and whose Industrial Service Agreement so provides.

Rate

<u>Energy Charge</u>

All kWh (net of losses)*.. @ 0.831¢ per kWh

*For the purpose of this Rate, losses shall be 3.34%, the average system losses on the Island Interconnected Grid for the last five years ending in 2016.

General

Details regarding the conditions of Service are outlined in the Industrial Service Agreements.

This rate schedule does not include the Harmonized Sales Tax (HST) that applies to electricity bills.

Schedule 4

Supply Cost Variance Deferral Account Definition

newfoundland labrador hydro

Newfoundland and Labrador Hydro
Supply Cost Variance Deferral Account Definition

Newfoundland and Labrador Hydro's ("Hydro") Supply Cost Variance Deferral Account is established to smooth rate impacts for Hydro's Utility customer, Newfoundland Power Inc. ("Newfoundland Power"), and Island Industrial customers and to provide Hydro the opportunity to recover supply cost variances between the forecasts reflected in customer rates and the actual costs incurred.

The formulae used to calculate the account's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A

1.0 Muskrat Falls Project ("Project") Cost Variances

The **Project Cost Variances** will reflect the variance from test year costs for the Muskrat Falls Purchase Power Agreement ("Muskrat Falls PPA") and the Transmission Funding Agreement ("TFA").

Project Cost Variances will be calculated monthly based on the following formula:

$$(A - A_T) + (B - B_T)$$

Where:

A = Actual Purchased Power Expense from Muskrat Falls PPA Charges;

A_T = Test Year Purchased Power Expense from Muskrat Falls PPA Charges;

B = Actual Purchased Power Expense from TFA Charges; and

B_T = Test Year Purchased Power Expense from TFA Charges.

2.0 Rate Mitigation Fund

Any funding to provide rate mitigation to offset the costs of the Project will be credited to the **Rate Mitigation Fund** component of the deferral account.

3.0 Project Cost Recovery

Charges applied to customers to recover Project costs will be credited to the **Project Cost Recovery** component of the deferral account and tracked by customer class.

4.0 Holyrood Thermal Generating Station ("Holyrood TGS") Fuel Cost Variance

Holyrood TGS Fuel Cost Variances will be calculated monthly based on the following formula:

$$(C - C_T)$$

Where:

C = Actual Holyrood TGS Fuel Cost incurred in the month to supply firm energy to customers on the Island Interconnected System; and

C_T = Test Year Holyrood TGS Fuel Cost in the month to supply firm energy to the customers on the Island Interconnected System.

5.0 Other Island Interconnected System Supply Cost Variance

The account shall be charged or credited monthly with the **Other Island Interconnected System Supply Cost Variance** incurred by Hydro on the Island Interconnected System that is in excess of the Cost Variance Threshold in the calendar year.

Variations resulting from both the price and volume of the following thermal generation sources shall be charged or credited to this account:

- Holyrood Combustion Turbine;
- Hardwoods Gas Turbine;
- Stephenville Gas Turbine;
- St. Anthony Diesel Plant; and
- Hawkes Bay Diesel Plant.

Variations resulting from the volume of the following on-island power purchases shall be charged or credited to this account:

- Nalcor Exploits;
- Star Lake;
- Rattle Brook;
- Corner Brook Pulp and Paper Limited ("CBPP") Cogeneration;
- St. Lawrence wind; and
- Fermeuse wind.

Variations from the price and volume of firm energy power purchases from CBPP shall be charged or credited to this account.

Variations resulting from the cost of off-island power purchases shall also be charged or credited to this account. Off-island power purchase costs shall not include any expenditure related to Muskrat Falls PPA, TFA or the Interim TFAs.

The **Other Island Interconnected System Supply Cost Variance** will be determined monthly by the following formula:

$$D + E + F + G$$

D = Test Year Thermal Generation Variances resulting from both price and volume;

Where:

D = (Actual Thermal Generation Cost in providing firm energy – Test Year Thermal Generation Cost).

E = Test Year Off-Island Power Purchase Variances resulting from both price and volume;

Where:

E = (Actual Off-Island Power Purchase Cost – Test Year Off-Island Power Purchase Cost).

F = Test Year Power Purchase Variances resulting from volume;

Where:

F = (Actual kWh Purchases – Test Year kWh Purchases) x (Test Year Purchase Cost in $/kWh).

G = Variances based on firm energy purchases from CBPP;

Where:

G = (Actual CBPP Power Purchase Cost – Capacity Assistance Adjustment) – (Test Year CBPP Firm Energy Power Purchase Cost).

"Capacity Assistance Adjustment" shall represent any change in fixed capacity assistance payments as a result of firm energy purchases from CBPP.

The **Cost Variance Threshold** equals ±$500,000[1] in a calendar year.

[1] The effective date of the cost variance threshold commences January 1, 2022.

6.0 Net Revenue from Exports Variance

The **Net Revenue from Exports Variance** is computed on monthly basis by the following formula:

$$(H_T - H)$$

Where:

Net Revenue from Exports reflect the revenues from Hydro exports less the costs incurred to export energy.

H_T = Test Year Net Revenues from Exports ($); and

H = Actual Net Revenues from Exports ($).

The account will be credited in December with an estimate of net export sales that occurred during the year but the actual settlement value will not be finalized until the following period. The account will be adjusted in the following period for any difference between the estimated and actual value.

Revenues from non-firm sales on the Island Interconnected System supplied by hydraulic generation and revenues from Rate No. 5.1L – Non-Firm Energy will also be credited to the Net Revenue from Exports Variance component.

7.0 Transmission Tariff Revenue Variance

For the purpose of this deferral account, Transmission Tariff Revenues reflect the transmission revenues paid by third parties to enable exports. The ***Transmission Tariff Revenue Variance*** is computed on monthly basis by the following formula:

$$(I_T - I)$$

Where:

I_T = Test Year Transmission Tariff Revenues paid by third parties ($); and

I = Actual Transmission Tariff Revenues paid by third parties ($).

8.0 Load Variation

Firm: Firm load variation is determined based on the revenue variation for firm energy sales compared with the test year Cost of Service Study firm sales. It is calculated separately for Newfoundland Power firm sales and Island Industrial firm sales on a monthly basis, in accordance with the following formula:

$$(J_T - J_A) \times K_R$$

Where:

J_T = Test Year Cost of Service Firm Sales, by customer class (kWh);

J_A = Actual Firm Sales, by customer class (kWh); and

K_R = Firm Energy Rate, by customer class.

Where the rate designs include more than one energy block, the excess energy rate will apply in computing **Load Variation** transfers.

9.0 Rural Rate Alteration

The **Rural Revenue Adjustment** transfers to Newfoundland Power: (i) changes in Hydro Rural revenues resulting from changes in Rural Rates between test years, and (ii) changes in Rural revenues on the Island Interconnected System as a result of changes in Rural load between test years. The **Rural Revenue Adjustment** is calculated on a monthly basis, in accordance with the following formula:

$$[(N_T-N_A) \times O_T] + [(P_T-P_A) \times Q_T]$$

Where:

N_T = Test Year Cost of Service rural rates;

N_A = Existing rural rates;

O_T = Test Year Billing Units (kWh, bills, billing demand);

P_T = Test Year kWh sales for Hydro Rural Island Interconnected (excluding street and area lighting);

P_A = Actual kWh sales for Hydro Rural Island Interconnected (excluding street and are lighting); and

Q_T = Test Year rates per class for Rural Island Interconnected System (excluding street and area lighting).

The **Rural Revenue Adjustment** will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion that the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to Hydro Rural Labrador Interconnected will be removed from the plan and written off to Hydro's net income (loss).

10.0 Greenhouse Gas Credit Revenues Variance

The **Greenhouse Gas Credit Revenues Variance** is computed on monthly basis, beginning on January 1, 2021, by the following formula:

$$(T_T - T)$$

Where:

T_T = Test Year Greenhouse Gas Credit Revenues ($); and

T = Actual Greenhouse Gas Credit Revenues ($).

Section B

1.0 Plan Balances

Separate plan balances for the Utility and Island Industrial customers will be maintained in this account as required. Transfers to the Utility balance will continue to reflect the monthly adjustments for the **Rural Rate Alteration**. No other transfers to the Utility balance and Industrial Customer balance will occur until further approval is obtained from the Board of Commissioners of Public Utilities ("Board").

2.0 Financing Costs

Financing charges on the plan balances will be calculated monthly using a financing rate calculated based on Hydro's short-term borrowing costs.The calculation of the annual short-term borrowing rate is as follows:

$$(U + V + W) \text{ divided by } (X + Y)$$

Where:

U = Credit Facility Interest and fees;

V = Promissory Note Interest and fees;

W = Recoverable portion of debt guarantee fees associated with promissory note balances;

X = Weighted Average Credit Facility Debt; and

Y = Weighted Average Promissory Note Debt Balances.

For the period of January to November the interest rate used will be the rate calculated based on the prior year-end. In the month of December, the interest expense will be trued up for the current year as the interest rate will be re-calculated and applied to the deferral account balance outstanding at the end of each month, inclusive of compound interest.

3.0 Customer Allocation

Customer Allocation of balances in the Supply Cost Variance Deferral Account will be subject to further approval by the Board.

4.0 Balance Disposition

Disposition of balances in the Supply Cost Variance Deferral Account will be subject to further approval by the Board.

5.0 Balance Transfers

The balances in the Supply Cost Variance Deferral Account shall be adjusted by other amounts as ordered by the Board.

Affidavit

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

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") pursuant to Section 70 of the *Act* for approval of a rate for Non-Firm Service in Labrador, and other associated matters and for the revision of the Supply Cost Variance Deferral Account definition. ("Application").

AFFIDAVIT

I, Kevin Fagan, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice President, Regulatory Affairs and Stakeholder Relations for Newfoundland and Labrador Hydro, the applicant named in the attached Revised Application.
2. I have read and understand the foregoing Revised Application.
3. To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this Revised Application are true.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador this 29th day of)
March 2023, before me:)

Commissioner for Oaths, Newfoundland and Labrador

Kevin Fagan

SAMANTHA KEATS
A Commissioner for Oaths in and for
the Province of Newfoundland and Labrador.
My commission expires on December 31, 2023