newfoundland labrador hydro

Newfoundland and Labrador Hydro
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September 16, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: Application for Adjustment to Wholesale Utility Rate

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") application for Update to the Wholesale Utility Rate charged to Newfoundland Power Inc. ("Newfoundland Power"), to become effective January 1, 2025.

An update to Hydro's wholesale utility rate structure would typically occur as part of Hydro's General Rate Application ("GRA"). However, the filing of Hydro's GRA has been delayed while awaiting the commissioning of the Muskrat Falls Project, the financial restructuring of the Muskrat Falls Project agreements, and the completion of the Government of Newfoundland and Labrador's ("Government") rate mitigation plan. With these activities complete, Hydro is preparing to file its next GRA in the second half of 2025; however, Hydro's GRAs have historically been lengthy proceedings and a filing in the second half of 2025 may not result in a Board Order until 2027.

To allow for a more timely update to Hydro's wholesale utility rate to reflect changes in the basis of Hydro's marginal cost, Hydro is proposing to update the wholesale rate in advance of its next GRA filing, with a proposed effective date of January 1, 2025. Although the proposed changes in the application will not have any impact on customer rates on January 1, 2025, updating the marginal cost of energy to reflect the market value of export sales will reduce the power purchase cost to Newfoundland Power for energy purchased in excess of 2019 Test Year quantities, reducing the additional costs to be recovered through Newfoundland Power's customer rate applications. The reduction in the marginal cost of energy and therefore the second block rate will create a benefit for customers through a reduction in the potential volatility associated with the July 1 customer rate change. Hydro expects that customer benefits, including the reduction in customer rate volatility, will be outlined in detail in Newfoundland Power's flow-through application to be filed on September 16, 2024.

Hydro's proposals are detailed in the attached application, with further details on the proposals provided in Schedule 1 to the application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd.rr

Encl.

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Application for Adjustment to Wholesale Utility Rate

September 16, 2024

An application to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

IN THE MATTER OF the *Electrical Power Control Act, 1994,* RSNL 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 Subsection 70(1) of the *Act* for the approval of an update to the wholesale utility rate charged to Newfoundland Power Inc. ("Newfoundland Power"), effective January 1, 2025.

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, 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 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. Section 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 Board Order No. P.U. 44(2004), the Board approved the transition from an energy-only wholesale rate for Newfoundland Power to a wholesale rate which included a billing demand charge and a blocking structure for energy charges. The Board also agreed that marginal costs should be considered in the future design of the wholesale rate.[1]

[1] Board Order No. P.U. 44(2004), p. 13.

5. In Hydro's 2017 General Rate Application ("GRA"), Hydro proposed that Newfoundland Power's wholesale rate would continue to include a second block rate reflecting Hydro's marginal cost based on the test year cost of No. 6 fuel used at the Holyrood Thermal Generating Station ("Holyrood TGS") and that the 2019 Test Year cost of No. 6 fuel would be set based on the most current, at that time, fuel rider forecast. The Board approved these proposals in Board Order No. P.U. 16, 2019, and the fuel price was subsequently set at $105.90 per barrel or 18.165 ¢ per kWh for the second block energy charge reflected in the wholesale rate effective October 1, 2019.[2] Those rates are currently in effect.

6. The current wholesale rate is a two block structure. The first block is broken down into two seasonal blocks, with the price remaining consistent over both seasonal blocks. The 2019 Test Year Revenue Requirement not recovered through the billing demand charge and the second block energy charge is used to compute the first block energy charge. The current charges are set out in Schedule 1 to this Application.

B. Application

7. In Newfoundland Power's 2025–2026 GRA, Hydro agreed to apply to the Board to revise the wholesale rate effective January 1, 2025.[3] Schedule 1 to this Application contains the detailed information and analysis supporting Hydro's proposed revisions to the wholesale rate; Attachment 1 to Schedule 1 provides a report by Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") regarding Hydro's proposals.

8. To allow for more timely updates to Newfoundland Power's wholesale rate to reflect changes in the basis of Hydro's marginal cost of energy, Hydro is proposing to update the wholesale rate in advance of its next GRA filing, with a proposed effective date of January 1, 2025. Further details on additional benefits to customers resulting from updating this rate are outlined in Section 2.5 of Schedule 1 to this application.

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[2] Board Order P.U. 30(2019).

[3] Newfoundland Power 2025–2026 General Rate Application; Information Item #2, sch. A.

Marginal Rate

9. The interconnection of the Island Interconnected System to the North Amercian grid allows Hydro to sell its surplus energy across the Maritime Link. If one additional unit of energy is required on the Island Interconnected System, it would be sourced by a reduction in the volume of Hydro's energy available for export. Therefore, the most appropriate basis for Hydro's marginal cost of energy is the opportunity cost of the market value of export sales and no longer the cost of Holyrood TGS fuel. The calculation of the 2025 marginal cost of energy and its appropriateness is discussed in more detail in Schedule 1 to this Application.

10. Hydro intends to propose updates of the marginal cost of energy reflected in the wholesale rate to Newfoundland Power on an annual basis to ensure the variability in Hydro's marginal cost of energy is appropriately represented in the second block price. Hydro proposes to maintain the proposed marginal cost rates from the date of implementation on January 1, 2025 until the next GRA where Hydro will propose the methodology for annual updates.

First Block Structure

11. Hydro is proposing to adjust to a quarterly blocking structure for the first block. This quarterly blocking structure allows Newfoundland Power to maintain the 2019 Test Year power purchase expense and cash flows, incorporating Hydro's proposed first and second block rates. This proposed blocking structure, as shown in Table 5 of Schedule 1, generally results in the same revenue pattern as the 2019 Test Year, as shown in Table 6 of Schedule 1.

Second Block Rate

12. The second block energy rate is proposed to have seasonal price boundaries based on the opportunity cost of the market value of export sales as Hydro's marginal cost of energy. The proposed seasonal boundaries, as discussed in Section 2.2 of Schedule 1 to this Application, are for the winter period of December to March and non-winter period from March to November. These are based on the observed seasonality of the market value of export sales and the considerable price variance experienced between periods within the calendar year. The proposed rates are based on Hydro's 2025 forecast average marginal cost of energy of 9.698¢ per kWh for the winter period and 3.354¢ per kWh for the non-winter period.

Demand Rate and Calculation of First Block Energy Charge

13. Hydro proposes to maintain the demand rate at the existing $5.00 per kW per month as approved in the 2017 GRA, and to continue the practice of utilizing the remaining 2019 Test Year Revenue Requirement to calculate the first block energy charge.

14. Schedule 2 to the Application provides the proposed Utility rate sheet with an effective date of January 1, 2025. The proposed rate sheet reflects the transition of the marginal rate to the opportunity cost of the market value of export sales, updates the second block energy rate to 9.698¢ per kWh for winter months and 3.354¢ per kWh for the non-winter months and amends the first block to a quarterly blocking structure.

C. Newfoundland and Labrador Hydro's Requests

15. Hydro requests the Board approve, effective January 1, 2025:

(i) Amendment to the first block of the wholesale rate to a quarterly blocking structure as follows:

Quarter ("Q")	**kWh per Month**
Q1 – January to March	590,000,000
Q2 – April to June	290,000,000
Q3 – July to September	130,000,000
Q4 – October to December	250,000,000

(ii) An updated first block energy rate of 8.515¢ per kWh;

(iii) An updated seasonal second block energy rate of 9.698¢ per kWh for winter months of December to March and 3.354¢ per kWh for the non-winter months of April to November.

(iv) The continuation of a demand rate at the existing $5.00 per kW per month; and

(v) The Utility Rate Sheet, attached as Schedule 2 to this Application.

D. Reason for Approval

16. Approval by the Board of the within proposals will ensure the utilization of the appropriate basis for Hydro's marginal cost of energy. Additionally, updating the marginal cost of energy underlying the second block price of Hydro's utility wholesale rate to reflect the opportunity

cost of the market value of exports will more accurately reflect Hydro's marginal cost in the rate charged to Newfoundland Power. In addition, it will reduce the power purchase cost to Newfoundland Power for energy purchased in excess of 2019 Test Year quantities, reducing the additional costs to be recovered through Newfoundland Power's July 1 customer rate applications. The reduction in the marginal cost of energy and therefore the second block rate will create a benefit for customers through a reduction in the potential volatility associated with the July 1 customer rate change.

E. Communications

17. Communications with respect to this Application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the province of Newfoundland and Labrador on this 16th day of September, 2024.

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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Schedule 1

Evidence Supporting Proposed Wholesale Utility Rate Adjustment

Contents

List of Attachments

1.0 Background

In Board Order No. P.U. 44(2004), the Board of Commissioners of Public Utilities ("Board") approved the transition from an energy-only wholesale rate to a wholesale rate which included a billing demand charge and a blocking structure for energy charges. The Board also agreed that marginal costs should be considered in the future design of the wholesale rate.[1] The existing wholesale rate charged to Newfoundland Power Inc. ("Newfoundland Power") was proposed as part of Newfoundland and Labrador Hydro's ("Hydro") 2017 General Rate Application ("GRA") filed on July 28, 2017. In Board Order No. P.U. 16(2019), the Board accepted the proposal that Newfoundland Power's wholesale rate would continue to include a second block rate reflecting Hydro's marginal cost based on the test year cost of No. 6 fuel used at the Holyrood Thermal Generating Station ("Holyrood TGS") and that the 2019 Test Year cost of No. 6 fuel would be set based on the most current fuel rider forecast. The fuel price was set at $105.90 per barrel or 18.165 ¢ per kWh for the second block energy charge reflected in the wholesale rate effective October 1, 2019, and is still in effect today.

Marginal cost of energy is defined as the incremental cost when producing one more unit of energy. The full commissioning of the Muskrat Falls Project in April 2023 provides Hydro with the ability to consistently deliver energy from the Muskrat Falls Generating Station to the Island and interconnects the Island Interconnected System to the North American grid, allowing Hydro to sell its surplus hydroelectric energy across the Maritime Link. If one additional unit of energy is required on the Island Interconnected System it would, in theory, be sourced by a reduction in the volume of Hydro's surplus energy available for export and therefore, the cost of Holyrood TGS fuel is no longer the most appropriate basis for Hydro's marginal cost of energy. This change results in the opportunity cost of the market value of export sales becoming the best measure of Hydro's marginal cost of energy, as discussed further in Section 2.2.

This change in Hydro's marginal cost of energy warrants a change to the wholesale rate charged to Newfoundland Power to update the basis of the second block rate from the cost of fuel used at the Holyrood TGS to the market value of export sales.

An update to Newfoundland Power's wholesale rate structure would typically occur as part of Hydro's GRA. However, the filing of Hydro's GRA has been delayed while awaiting the commissioning of the

[1] Board Order No. P.U. 44(2004), p. 13.

Muskrat Falls Project, the financial restructuring of the Muskrat Falls Project agreements, and the completion of the Government of Newfoundland and Labrador's ("Government") rate mitigation plan. The financial restructuring of the Muskrat Falls Project agreements was completed on March 31, 2022, full commissioning of the Muskrat Falls Project was completed on April 14, 2023, and the finalization of the Government's rate mitigation plan was announced on May 16, 2024. With these activities complete, Hydro is preparing to file its next GRA in the second half of 2025. Hydro's GRAs have historically been lengthy proceedings; a filing in the second half of 2025 may not result in a Board Order until 2027.

To allow for more timely updates to Newfoundland Power's wholesale rate to reflect changes in the basis of Hydro's marginal cost, Hydro is proposing to update the wholesale rate in advance of its next GRA filing, with a proposed effective date of January 1, 2025. Further details on additional benefits to customers resulting from updating this rate are outlined below and in Section 2.5.

In Newfoundland Power's 2025–2026 GRA, Hydro agreed to apply to the Board to revise the wholesale rate effective January 1, 2025. An agreement to do so was signed by Newfoundland Power, the Consumer Advocate, and Hydro and proposed a framework for the revision of the wholesale rate ("Settlement Agreement").[2] Key points noted in the framework include:

- Customer benefits of the revised wholesale rate implemented on January 1, 2025 include lower marginal power supply energy costs and a reduction in July 1 customer rate change volatility; and
- Hydro will file an application with the Board on or about September 16, 2024 subject to the following principles:
    - Wholesale rate implementation on January 1, 2025, would have no customer rate impact;
    - There would be no adverse impact to Hydro's Industrial customers; and
    - Customer rate changes are maintained consistent with OC2024-062 and the Government's rate mitigation plan.

[2] Newfoundland Power 2025–2026 General Rate Application; Information Item #2, sch. A.

Adhering to the principles established in the framework and recognizing that the marginal costs on the Island Interconnected System should reflect the market value of export sales, Hydro is proposing to update the wholesale rate charged to Newfoundland Power.

Hydro's application proposes a seasonal second block rate with a corresponding change to the first block rate to ensure Hydro's recovery continues to equal its 2019 Test Year Revenue Requirement. Additionally, at the request of Newfoundland Power, Hydro is proposing a change in the first block to a quarterly blocking structure.

At this time, there is no proposed change to the billing demand charge included in the wholesale rate. However, Hydro intends to review the demand rates for all customers based on a cost of service incorporating updated costs, including the impact of the Muskrat Falls Project costs and the Government's rate mitigation plan. Any updates to these rates will be included as part of its next GRA.

As of January 1, 2025, the proposed effective date, there is no customer impact associated with this application or Newfoundland Power's corresponding flow-through application.

2.0 Hydro's Proposal

In developing its proposal to update the marginal cost of energy applicable to Newfoundland Power's second block rate, Hydro engaged Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") to provide an opinion on updating marginal costs between test years and to review Hydro's calculation and recommend the 2025 marginal cost to serve Newfoundland Power, applicable to the second block rate. CA Energy Consulting's report titled "Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier" ("CA Energy Consulting Report") is provided as Attachment 1 to this evidence.

2.1 Updating the Wholesale Rate between Test Years

Rate changes in between GRA filings are not historically unusual. The introduction of the Project Cost Recovery Rider was approved in 2022, and rate adjustments resulting from the Rate Stabilization Plan are approved annually. Hydro's consultation with CA Energy Consulting found that frequent updates to tariff rates are commonly accepted in regulatory practice and the CA Energy Consulting Report lists examples of these including those associated with underlying cost changes and updates.[3]

CA Energy Consulting notes that more frequent updates to rates can reduce balances which may build up over time in deferral accounts, representing revenue overages or shortfalls; Hydro submits that updating the wholesale rate in advance of its next GRA may help mitigate customer rate volatility, as further outlined in Section 2.5. Hydro is proposing to update the wholesale rate in advance of its next GRA, with annual updates thereafter, for these reasons and to ensure that the second block price more accurately reflects Hydro's marginal cost of energy.

2.2 Calculation of the Marginal Cost of Energy

In late 2015 and early 2016, in compliance with the 2013 GRA proceeding, Hydro submitted a marginal cost study for the Island Interconnected System to the Board[4] that included reports authored by CA Energy Consulting. This study, which was filed in two parts with the first part focused on methodology, reviewing methodology options in consideration of the future rate structure changes that may be required upon commissioning of the Muskrat Falls Project. The second part further discussed marginal cost methodology and its application, and presented estimates of marginal costs for the Island Interconnected System for 2019.[5] The 2015 Study concluded that Hydro's marginal cost of energy would be the opportunity cost of the market export sales upon the full commissioning of the Muskrat Falls Project.

Hydro subsequently provided its Marginal Cost Study Update – 2018 ("2018 Update"),[6] which updated its 2015 Study to address changes in assumptions, such as revised load forecasts, the timing of full commissioning of the Muskrat Falls Project, and forecast market export prices. A report from CA Energy Consulting was also included in the 2018 Update. Hydro's marginal cost of energy calculation methodology did not change as part of this update and the underlying driver of the marginal cost of energy continued to be the opportunity cost of the market value of export sales that would reflect a

[3] "Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier," Christensen Associates Energy Consulting, LLC, sec. III, p. 5.

[4] "Marginal Cost Report, Part I – Methodology: Estimation of Marginal Costs of Generation and Transmission Services for 2019," Christensen Associates Energy Consulting, December 29, 2015, and "Marginal Cost Report, Part II – Estimation: Marginal Costs of Generation and Transmission Services for 2019," Christensen Associates Energy Consulting, February 26, 2019 ("2015 Study").

[5] 2019 was assumed to be the first full year of service for the Muskrat Falls Project at the time.

[6] "Marginal Cost Study Update – 2018," Newfoundland and Labrador Hydro, November 15, 2018.

seasonal pattern of winter and non-winter seasons. A further update to the study was provided in 2021 and filed with the Board ("2021 Update"),[7] including a report from CA Energy Consulting and updated calculations based on the most recent assumptions and information available. There was no change to the underlying methodology used to calculate the marginal cost of energy in the 2021 Update.

The purpose of updates to Hydro's marginal cost study is to provide a periodic review of Hydro's marginal cost calculation methodology, with the next update to its study planned for the later half of 2025. Hydro updates the calculation of its marginal cost of energy each year using the methodology consistent with its most recent marginal cost study. The concept of Hydro's marginal cost of energy being the opportunity cost of the market value of export sales was implemented into rates as part of Hydro's application for a non-firm rate for Labrador filed on September 15, 2022, and approved by the Board effective March 1, 2024.[8]

2.2.1 2025 Marginal Cost of Energy

To calculate the proposed 2025 marginal cost of energy to serve Newfoundland Power, Hydro utilized a methodology consistent with the 2018 and 2021 Updates, reflecting appropriate changes in underlying assumptions such as forecast export prices and the date of full commissioning the Muskrat Falls Project.

Hydro has concluded that its marginal cost of energy to serve Newfoundland Power is based on the opportunity cost of the market value of export sales into the New England market. This conclusion is based on the fact that, in theory, each additional kWh of energy used to service Newfoundland Power on the Island Interconnected System would have otherwise been sold in export markets over Hydro's transmission rights associated with the Maritime Link through to markets in the Northeast, either into the New England market or through other commercial contracts that are linked to the New England market price.

Given the seasonality of the market value of export sales and the considerable price variance experienced between periods within the calendar year, and consistent with its most recent marginal cost studies, Hydro has proposed a seasonal second block rate for winter and non-winter periods.

[7] "Electrification, Conservation and Demand Management Plan 2021-2025", Newfoundland and Labrador Hydro, June 11, 2021, TC-IC-NLH-001, May 25, 2022.
[8] Board Order No. P.U. 34(2023).

CA Energy Consulting's analysis shows the calculation of Hydro's monthly marginal cost of energy using estimated 2025 prices and Newfoundland Power loads for 2021, 2022, and 2023 for illustrative purposes. As seen in the chart, there are clear seasonal differences in price.[9]

CA Energy Consulting recommends that the marginal cost of energy to serve Newfoundland Power be defined seasonally with a four-month winter period from December to March and the non-winter period from April to November, consistent with Hydro's most recent marginal cost studies and current proposal.

CA Energy Consulting recommends the use of market-based futures prices over the near term as the basis for setting second block prices in the proposed wholesale rate for Newfoundland Power, consistent with Hydro's current methodology. The application of market-based futures prices as the basis for determining the market value of energy over the near-term period is a commonly accepted practice across wholesale markets and widely used by electricity service providers. The CA Energy Consulting Report also recommends that export price projections be adjusted for expected CAD/USD currency exchange and transmission path charges, similar to the approach used within Hydro's methodology for the calculation of marginal cost.

CA Energy Consulting's analysis reviewed and utilized underlying forecast market prices and marginal cost data provided by Hydro and resulted in a recommended 2025 marginal cost of energy as outlined in the CA Energy Consulting Report and presented in Table 1.

Table 1: CA Energy Consulting's Recommended 2025 Marginal Cost of Energy (¢ per kWh)

Winter (December to March)	Non-Winter (April to November)
9.698	3.354

2.3 Rate Design for Newfoundland Power

2.3.1 Existing Wholesale Rate

The Board approved the transition from an energy-only wholesale rate to a wholesale rate which included a billing demand charge and a blocking structure for energy charges in Board Order No.

[9] "Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier," Christensen Associates Energy Consulting, LLC, p. 9, Table 4.

P.U. 44(2004). The Board also agreed that marginal costs should be considered in the future design of the wholesale rate.

The mechanics for determining the wholesale rate for Newfoundland Power have since included maintaining a second block price signal to reasonably reflect the price of Holyrood TGS fuel, considering the demand rate in light of both marginal and embedded capacity costs, and determining the first block rate to ensure the overall wholesale rate recovers the revenue requirement to serve Newfoundland Power. The details of the existing rate are provided in the following sections.

First Block

Block Structure

The first block is currently broken down into two seasonal blocks, as shown in Table 2.

Table 2: Existing First Block Seasonal Blocking Structure

Season	kWh per Month
Winter (November to April)	410,000,000
Non-Winter (May to October)	250,000,000

Price

The price of the first block remains consistent over the two seasonal blocks. The 2019 Test Year Revenue Requirement not recovered through the billing demand charge and the second block energy charge is used to compute the first block energy charge, currently set as part of the 2017 GRA at 2.444¢ per kWh.

Second Block

The existing second block energy rate is 18.165¢ per kWh reflects the $105.90 per barrel fuel price divided by the 2019 Test Year Holyrood TGS fuel conversion rate of 583 kWh per barrel.[10]

Demand Charge

The existing demand charge of $5.00 per kW per month was agreed upon amongst the parties and approved by the Board in the 2017 GRA, considering marginal capacity costs and the increase in embedded demand costs.

[10] Second Block Energy Rate = 2019 Test Year price per barrel/2019 Test Year Holyrood fuel conversion rate ($105.90/583 = 18.165¢ per kWh).

Table 3 shows the breakdown of the rate components and Table 4 displays the breakdown of the 2019 Test Year Revenue Requirement by rate component.

Table 3: Breakdown of the Existing Wholesale Rate

Rate Component	Rate
First Block	2.444
Second Block (¢ per kWh)	18.165
Billing Demand Charge ($ per kW)	5.000

Table 4: Newfoundland Hydro 2019 Test Year Utility Revenue (Existing)[11,12]

Month	NP Purchases	First Block			Second Block			Billing Demand			Total
	(kWh)	Size (kWh)	Rate (¢/kWh)	Revenue ($)	Size (kWh)	Rate (¢/kWh)	Revenue ($)	Demand (kW)	Rate ($/kW)	Revenue ($)	Revenue ($)
January	715,400,000	590,000,000	8.515	50,240,766	125,400,000	9.698	12,161,292	1,263,689	5.00	6,318,445	68,720,503
February	648,500,000	590,000,000	8.515	50,240,766	58,500,000	9.698	5,673,330	1,263,689	5.00	6,318,445	62,232,541
March	646,000,000	590,000,000	8.515	50,240,766	56,000,000	9.698	5,430,880	1,263,689	5.00	6,318,445	61,990,091
April	527,700,000	290,000,000	8.515	24,694,614	237,700,000	3.354	7,972,458	1,263,689	5.00	6,318,445	38,985,517
May	421,700,000	290,000,000	8.515	24,694,614	131,700,000	3.354	4,417,218	1,263,689	5.00	6,318,445	35,430,277
June	345,200,000	290,000,000	8.515	24,694,614	55,200,000	3.354	1,851,408	1,263,689	5.00	6,318,445	32,864,467
July	307,900,000	130,000,000	8.515	11,069,999	177,900,000	3.354	5,966,766	1,263,689	5.00	6,318,445	23,355,210
August	300,500,000	130,000,000	8.515	11,069,999	170,500,000	3.354	5,718,570	1,263,689	5.00	6,318,445	23,107,014
September	314,500,000	130,000,000	8.515	11,069,999	184,500,000	3.354	6,188,130	1,263,689	5.00	6,318,445	23,576,574
October	413,700,000	250,000,000	8.515	21,288,460	163,700,000	3.354	5,490,498	1,263,689	5.00	6,318,445	33,097,403
November	495,500,000	250,000,000	8.515	21,288,460	245,500,000	3.354	8,234,070	1,263,689	5.00	6,318,445	35,840,975
December	664,100,000	250,000,000	8.515	21,288,460	414,100,000	9.698	40,159,418	1,263,689	5.00	6,318,445	67,766,323
	5,800,700,000	3,780,000,000		321,881,517	2,020,700,000		109,264,038			75,821,340	506,966,895

2.3.2 Proposed Wholesale Rate

The mechanics for determining the wholesale rate for Newfoundland Power remain the same in Hydro's proposal with the exception of the second block price signal, adjusted to reflect Hydro's marginal cost of energy. As discussed previously, the updated marginal cost of energy is the market value of export sales. At the request of Newfoundland Power, Hydro is proposing to adjust to a quarterly blocking structure for the first block. The details of the purpose and effect of this request is discussed in more detail below. The demand rate remains at $5.00 per kW per month as approved in the 2017 GRA, and the practice of utilizing the remaining 2019 Test Year Revenue Requirement to calculate the first block energy charge also remains consistent.

[11] "2017 General Rate Application – Compliance Application," Newfoundland and Labrador Hydro, July 11, 2019, exh. 14, p. 19 of 107.

[12] The variance in the first block energy revenue and total revenue is due to rounding on the first block energy rate.

The details of the proposed rate are provided in the following sections. There is no customer impact on January 1, 2025 associated with the proposed changes outlined below.

First Block

Block Structure

At the request of Newfoundland Power, Hydro is proposing to revise the blocking structure of the first block from a two-season blocking structure to a quarterly blocking structure, as outlined in Table 5.

Table 5: Proposed First Block Quarterly Blocking Structure

Quarter	kWh per Month
Q1[13] – January to March	590,000,000
Q2[14] – April to June	290,000,000
Q3[15] – July to September	130,000,000
Q4[16] – October to December	250,000,000

This quarterly blocking structure allows Newfoundland Power to maintain the 2019 Test Year power purchase expense and cash flows, incorporating Hydro's proposed first and second block rates. The existing seasonal blocks created significant changes in Q2 and Q3 revenue for Hydro and power purchase expense for Newfoundland Power. Newfoundland Power's proposed blocking structure is acceptable by Hydro at this time as it generally results in the same revenue pattern as the 2019 Test Year, as shown in Table 6. The blocking structure will be reviewed again as part of Hydro's next GRA.

Table 6: Hydro's Quarterly Sales to Newfoundland Power – Existing versus Proposed ($000s)

	Q1[13]	Q2[14]	Q3[15]	Q4[16]	Total
Existing[17]	190,685	111,058	68,693	136,531	506,967
Quarterly Blocks[18]	192,943	107,280	70,039	136,705	506,967
Seasonal Blocks[19]	193,625	97,608	85,142	130,592	506,967
<u>**Variance from Existing**</u>					
Quarterly Blocks	2,258	(3,778)	1,346	174	-

[13] First Quarter ("Q1").
[14] Second Quarter ("Q2").
[15] Third Quarter ("Q3").
[16] Fourth Quarter ("Q4").
[17] Approved in Hydro's 2017 GRA.
[18] Rate structure proposed in this application to be effective January 1, 2025.
[19] Estimated sales based on existing first block size of 410 GWh in winter (December to March) and 250 GWh for non-winter months (April to November).

Seasonal Blocks	2,940	(13,450)	16,449	(5,939)	-

Price

Consistent with the existing wholesale rate mechanics, the 2019 Test Year Revenue Requirement not recovered through the billing demand charge and the second block energy charge is used to compute the first block energy charge, proposed to be 8.515¢ per kWh effective January 1, 2025.

Second Block

The second block energy rate is proposed to have seasonal price boundaries, as described in Section 2.2, based on the opportunity cost of the market value of export sales as Hydro's marginal cost of energy. CA Energy Consulting recommends seasonal boundaries for the winter period of December to March and non-winter period from April to November, based on observed price variations, consistent with Hydro's most recent marginal cost studies. The calculated and recommended rates are based on Hydro's 2025 forecast average marginal cost of energy of 9.698¢ per kWh for the winter period and 3.354¢ per kWh for the non-winter period.

Billing Demand Charge

Hydro is not proposing any change to the existing demand charge of $5.00 per kW per month. The demand rates for all customers will be reviewed based on a cost of service incorporating updated costs, including the impact of the Muskrat Falls Project costs and the Government's rate mitigation plan, as part of Hydro's next GRA.

Table 7 shows the breakdown of the proposed revised wholesale rate components. The proposed rate structure results in the same total 2019 Test Year Revenue Requirement approved in the 2017 GRA, as presented in **Error! Reference source not found.**.

Table 7: Breakdown of the Proposed Wholesale Rate

Rate Component	Rate
First Block (¢ per kWh)	8.515
Second Block	
Winter – December to March (¢ per kWh)	9.698
Non-Winter – April to November (¢ per kWh)	3.354
Billing Demand Charge ($ per kW)	5.000

Table 8: Newfoundland Hydro 2019 Test Year Utility Revenue (Proposed)

		First Block			Second Block			Billing Demand			Total
Month	NP Purchases (kWh)	Size (kWh)	Rate (¢/kWh)	Revenue ($)	Size (kWh)	Rate (¢/kWh)	Revenue ($)	Demand (kW)	Rate ($/kW)	Revenue ($)	Revenue ($)
January	715,400,000	590,000,000	8.515	50,240,766	125,400,000	9.698	12,161,292	1,263,689	5.00	6,318,445	68,720,503
February	648,500,000	590,000,000	8.515	50,240,766	58,500,000	9.698	5,673,330	1,263,689	5.00	6,318,445	62,232,541
March	646,000,000	590,000,000	8.515	50,240,766	56,000,000	9.698	5,430,880	1,263,689	5.00	6,318,445	61,990,091
April	527,700,000	290,000,000	8.515	24,694,614	237,700,000	3.354	7,972,458	1,263,689	5.00	6,318,445	38,985,517
May	421,700,000	290,000,000	8.515	24,694,614	131,700,000	3.354	4,417,218	1,263,689	5.00	6,318,445	35,430,277
June	345,200,000	290,000,000	8.515	24,694,614	55,200,000	3.354	1,851,408	1,263,689	5.00	6,318,445	32,864,467
July	307,900,000	130,000,000	8.515	11,069,999	177,900,000	3.354	5,966,766	1,263,689	5.00	6,318,445	23,355,210
August	300,500,000	130,000,000	8.515	11,069,999	170,500,000	3.354	5,718,570	1,263,689	5.00	6,318,445	23,107,014
September	314,500,000	130,000,000	8.515	11,069,999	184,500,000	3.354	6,188,130	1,263,689	5.00	6,318,445	23,576,574
October	413,700,000	250,000,000	8.515	21,288,460	163,700,000	3.354	5,490,498	1,263,689	5.00	6,318,445	33,097,403
November	495,500,000	250,000,000	8.515	21,288,460	245,500,000	3.354	8,234,070	1,263,689	5.00	6,318,445	35,840,975
December	664,100,000	250,000,000	8.515	21,288,460	414,100,000	9.698	40,159,418	1,263,689	5.00	6,318,445	67,766,323
	5,800,700,000	3,780,000,000		321,881,517	2,020,700,000		109,264,038			75,821,340	506,966,895

2.4 Supply Cost Variance Deferral Account

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

The Load Variation component of the SCVDA calculates the firm load variation 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 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.

If the proposed rates are approved effective January 1, 2025, the firm energy rate applicable to Newfoundland Power by month will be used to calculate the Load Variation. The current SCVDA definition allows for this change in calculation; therefore, no change in the current account definition is required or proposed as part of this application.

2.5 Customer Benefits

Although the proposed changes in this application will not have any impact on customer rates on January 1, 2025, updating the marginal cost of energy to reflect the value of exports will reduce the power purchase cost to Newfoundland Power for energy purchased in excess of 2019 Test Year quantities, reducing the additional costs to be recovered through Newfoundland Power's July 1 customer rate applications. The reduction in the marginal cost of energy and therefore the second block rate will create a benefit for customers through a reduction in the potential volatility associated with the July 1 customer rate change. The update to the wholesale rate is estimated to avoid a 2.9% [20] rate increase on July 1, 2026 and will provide stability for future annual rate updates, as provided in Newfoundland Power's evidence. Customer benefits, including the reduction in customer rate volatility, are outlined in detail in Newfoundland Power's flow-through application to be filed on September 16, 2024.

Based on Newfoundland Power's forecast of power purchases from Hydro for 2025, pending approval of the proposals in this application and an effective date of January 1, 2025, Hydro's billed revenue and Newfoundland Power's power purchase expense are estimated to be approximately $11.8 million less in 2025 and $6.8 million less in 2026, as shown in Table 9. These calculations are estimates, based on the load forecast provided by Newfoundland Power; therefore, actual results may differ.

Table 9: Change in Forecast Revenue from Newfoundland Power ($000s)[21,22]

Year	Existing Rates	Proposed Rates	Change
2025	530,628	518,845	(11,783)
2026	522,388	515,632	(6,756)

2.6 Frequency of Updates to the Wholesale Rate and Hydro's Marginal Cost

Under the existing wholesale rate, changes in Holyrood TGS fuel prices from the test year were updated using a rider based on forecast fuel prices adjusted annually through July 1 utility rate applications.

[20] Newfoundland Power Wholesale Rate Flow-Through Report, Page 8 of 10, fn. 29.
[21] Based on forecast of 2025 and 2026 power purchases from Hydro provided by Newfoundland Power.
[22] The Load Variation calculation in Hydro's SCVDA will adjust Hydro's revenue to the 2019 Test Year.

Hydro is proposing to update the second block rate of its wholesale rate for Newfoundland Power to reflect its marginal cost of energy, now derived from the opportunity cost of the market value of export sales. Electricity export prices will vary from month to month and year to year and are highly dependent on factors such as the supply and demand of electricity and natural gas in the market and other global events, all of which are outside of Hydro's control. Therefore, variability in Hydro's marginal cost of energy is likely. The CA Energy Consulting Report provides an analysis of the variability of export prices based on historical experience.[23]

Hydro updates its calculation of marginal cost on an annual basis. To ensure the second block price more accurately reflects Hydro's marginal cost of energy, Hydro intends to propose updates of the marginal cost of energy reflected in the wholesale rate to Newfoundland Power on an annual basis. Updates to the price can also reduce the potential for large variances in deferral accounts, helping to mitigate customer rate volatility.

Hydro proposes to maintain the proposed marginal cost rates from the date of implementation on January 1, 2025, until the next GRA where Hydro will propose the methodology for annual updates. If Hydro anticipates the GRA will not be concluded by July 1, 2026, a separate application will be filed in advance of the conclusion of the GRA for July 1, 2026 Utility Rate Adjustments proposing an update to the marginal cost rates.

2.7 Rate Mitigation

On May 16, 2024, the Government announced the finalization of its rate mitigation plan. The plan, applying only to Island Interconnected System customers paying for the Muskrat Falls Project costs, will ensure the domestic residential rate increases attributable to Hydro's costs are targeted at 2.25% annually up to and including 2030 ("Hydro Target Rate Increase"). For other customers on the Island Interconnected System, including Island Industrial Customers, rates will increase in a manner that is compatible with the Hydro Target Rate Increase. The first rate change implemented under this plan became effective August 1, 2024, as part of Hydro's Application for July 1, 2024 Utility Rate Adjustments.[24]

[23] "Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier," Christensen Associates Energy Consulting, LLC, sec. vi, p. 11.
[24] Board Order No. P.U. 15(2024).

The implementation of the proposed second block rate for Newfoundland Power will not interfere with the implementation of future rate changes in accordance with the Government's rate mitigation plan. If Hydro's proposals are approved with an effective date of January 1, 2025, there will be no rate change for customers on January 1, 2025, and the annual 2.25% rate increase for domestic customers associated with Hydro's costs, as per the rate mitigation plan, will be incorporated into Hydro's application for July 1, 2025 Utility Rate Adjustments.

2.8 Industrial Customers

On July 5, 2024,[25] the Island Industrial Customer Group ("IIC Group") submitted comments to the Board on the Settlement Agreement to establish a new wholesale rate for Newfoundland Power. The IIC Group identified the following preliminary issues that they submit require further consideration before Hydro's proposal successfully meets the principles set out in the framework contained within the Settlement Agreement:

1) Whether the new wholesale rate will be revenue neutral, particularly in the context of the operation of the SCVDA;

2) The marginal cost of serving winter load growth and capacity;

3) Whether new wholesale rates should be established without changes to demand rates;

4) The very limited opportunity to date to test export price development and its reasonableness as a benchmark for the marginal cost of energy; and

5) Lack of fairness between the pricing of firm energy to the Industrial Customers ("IC") and the proposed firm non-winter power to be supplied to Newfoundland Power under a new wholesale rate.

Hydro recognizes the concerns of the IIC Group and offers the following responses to their list of issues:

1) The new wholesale rate will be revenue neutral for Hydro, as demonstrated in Table 4 and Table 8. The total revenue under the existing rate structure equals the total revenue under the proposed rate structure, and also the total revenue of the 2019 Test Year approved as part of Hydro's 2017 GRA. Hydro sales to Newfoundland Power that are above or below 2019 Test Year

[25] "2025-2026 General Rate Application," Newfoundland Power Inc, December 12, 2023, Letter of Comment of the Island Industrial Customer Group, Stewart McKelvey Lawyers, July 5, 2024.

quantities will be sold at the proposed second block rate and the variation from test year is reflected in the Load Variation – Utility component of the SCVDA.

Hydro's SCVDA also includes a "Net Revenue from Exports Variance" component which captures the variance of Hydro's net export sales revenue from the test year. In theory, any change in the volume of energy required to serve Newfoundland Power on the Island Interconnected System would have an equal and offsetting impact on the energy available for export. The increase or decrease in revenue at the marginal cost of export sales recorded in the Load Variation will therefore generally be offset by an increase or decrease in the "Net Revenue from Exports Variance," resulting in minimal impact on the overall balance in the SCVDA.

This produces the same net result in the Rate Stabilization Plan when No. 6 fuel at the Holyrood TGS is the basis for the marginal cost of energy. The second block energy rate and the test year fuel cost offset each other in the Load Variation component. Between test years, the price of fuel reflected in rates was adjusted based on a forecast of fuel prices through the fuel rider. The funds collected from the fuel rider were applied to the Newfoundland Power or the IC current plan balances and the price variance allocated based on energy ratios. The allocation methodology for and disposition of the current SCVDA will be proposed after the conclusion of Hydro's next GRA.

2) The seasonal marginal cost of energy of the second block rate proposed by CA Energy Consulting recognizes the difference in the cost of serving winter load. CA Energy Consulting proposed a rate of 9.698 ¢ per kWh during the winter months[26] and 3.354 ¢ per kWh for non-winter months.[27] Hydro's current proposals do not address the marginal cost of capacity but that will be considered as part of Hydro's review of the demand rate for all customers during the next GRA, along with the embedded demand costs to determine changes in proposed demand rates for Newfoundland Power and IC.

3) The demand rate is not being addressed as part of Hydro's current wholesale rate application. The purpose of the current application is to update the marginal cost of energy underlying the second block of Hydro's wholesale utility rate charged to Newfoundland Power. This is being done in advance of Hydro's next GRA, to provide a benefit to customers while ensuring Hydro's

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[26] Defined as December to March.
[27] Defined as April to November.

revenue requirement continues to balance back to the 2019 Test Year. Hydro recognizes that demand charges will increase for both Newfoundland Power and the Island Customer when the cost of service is updated for the next test year, incorporating Muskrat Falls Project costs, as part of Hydro's next GRA. Hydro is not currently proposing increases in the demand rate for either Newfoundland Power or the Island Customer at this time.

4) As described in Section 2.2, the marginal cost of energy, as well as capacity, and Hydro's calculation methodology has been reviewed several times by CA Energy Consulting. This was completed at Hydro's request as part of Hydro's 2015 Study and the 2018 and 2021 Updates, both of which were filed with the Board. These reviews were undertaken to inform the Board and other parties of the change in marginal cost on the Island Interconnected System resulting from the commissioning of the Muskrat Falls Project.

The 2015 Study was filed in two parts, the first part of the study concluded, amongst other things, that opportunity cost is an appropriate basis for determining the economic value of energy. The second part presented estimates of marginal costs for the Island Interconnected System for 2019.

On November 15, 2018, Hydro filed the 2018 Update that included changes in assumptions, such as revised load forecasts, the timing of full commissioning of the Muskrat Falls Project, and a calculation of Hydro's marginal cost for 2021–2029. There was no change to the methodology used to calculate Hydro's marginal cost from that proposed in the 2015 Study. The 2018 Update explained the roles of marginal cost of energy in efficient pricing and the methods used to estimate generation and transmission marginal costs for the period 2021–2029. The information was provided to assist the Board and parties in further understanding the contributing factors to the marginal cost estimates and their potential use in electricity pricing, and conservation and demand management.

Hydro's 2021 Update was filed with the Board in Request for Information TC-IC-NLH-001 relating to Hydro's Application for Approvals Required to Execute Programming Indentified in the Electrification, Conservation and Demand Management Plan 2021–2025 and included a report from CA Energy Consulting and updated calculations of Hydro's marginal cost based on the most recent assumptions and information available. There was no change to the underlying methodology used to calculate the marginal cost of energy in the 2021 Update.

The CA Energy Consulting Report utilizes the same methodology from Hydro's marginal cost studies to recommend a marginal cost rate to be implemented for Newfoundland Power's second block energy charge. This report, along with the previous periodic updates, continues the past practice of informing the Board and other parties of the marginal costs on the Island Interconnected System.

5) The current rate structures for Newfoundland Power and IC's are different. The rate structure for Newfoundland Power consists of a billing demand charge and a two-block energy charge. The energy blocking structure has been set at a level allowing Newfoundland Power to see the marginal cost of energy pricing in all months, currently set at 18.165¢ per kWh.

The existing rate structure for Industrial Customers consists of a billing demand charge based on test year embedded costs and a single, average embedded cost energy rate based on test year costs to serve Industrial Customers, currently 4.428¢ per kWh, applied to all firm energy. Industrial Customers also have access to non-firm energy at market-based prices effective March 1, 2024.

Under the existing wholesale rate, additional energy is sold to Newfoundland Power at the second block rate of 18.165¢ per kWh. In comparison, additional energy sold to Industrial customers for quantities within their respective Power Service Agreement is at the firm energy rate of 4.428¢ per kWh. For loads in excess of firm load, non-firm rates apply based on market-based prices effective March 1, 2024. Currently, the rate for Newfoundland Power's purchase of firm excess energy is 18.165¢ per kWh, or 310% higher than the firm industrial customer rate of 4.428¢ per kWh. The proposed rate structure will reduce the second block rate for Newfoundland Power to 3.354¢ per kWh during the non-winter period, or 24.3% less than the Industrial customer firm rate. However, the average cost of second block sales to Newfoundland Power forecast for 2025, based on the proposed rate structure, is 5.471¢ per kWh[28], which continues to be higher than the Industrial customer firm rate of 4.428¢ per kWh.

3.0 Summary and Conclusion

Hydro is proposing to update the wholesale rate charged to Newfoundland Power effective January 1, 2025. The proposed update to the rate structure for Newfoundland Power reflects a change

[28] Based on Newfoundland Power's forecast load for 2025, Second Block Revenue/Second Block Size ($116,204,686/2,123,700,000).

in Hydro's marginal cost of energy which has historically been set based on the cost of fuel at the Holyrood TGS but has recently transitioned to the opportunity cost of the market value of export sales.

The update to the wholesale rate proposes a change to the second block energy rate from 18.165¢ per kWh, which became effective October 1, 2019 when rates were implemented as a result of Hydro's 2017 GRA, to the proposed seasonal second block rate of 9.698¢ per kWh for winter months and 3.354¢ per kWh for the non-winter months. In addition, at the request of Newfoundland Power, Hydro is proposing to change the first block to a quarterly blocking structure to maintain the same pattern of power purchase expense and cash flow as the existing rate structure.

Hydro would normally update the wholesale rate structure for Newfoundland Power during a GRA, with the next GRA currenlty scheduled to be filed in the second half of 2025. However, with the finalization and announcement of the Government's rate mitigation plan on May 16, 2024, providing certainty for rate increases attributable to Hydro and for other customers on the Island Interconnected System up to and including 2030, and the forecast customer benefits of updating the second block rate before the conclusion of the next GRA, Hydro is proposing to modify the rate structure effective January 1, 2025. As part of Hydro's next GRA, Hydro will propose annual updates to the underlying marginal cost of energy included in the second block price of the wholesale rate, with the next update anticipated to be effective July 1, 2026.

Updating the wholesale rate charged to Newfoundland Power will complement the rate mitigation plan by providing additional rate stability for customers before the conclusion of Hydro's next GRA with no customer impact anticipated when the proposals are made effective January 1, 2025.

Attachment 1

Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier

newfoundland labrador hydro

Two-Tier Tariff for G&T Services Provided to Newfoundland Power: Working Mechanics and Marginal Cost of 2nd Tier

for

Newfoundland and Labrador Hydro

By

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September 3, 2024

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REPORT

TWO-TIER TARIFF FOR G&T SERVICES PROVIDED TO NEWFOUNDLAND POWER: WORKING MECHANICS AND MARGINAL COST OF 2ND TIER

prepared for
Newfoundland and Labrador Hydro

prepared by
Robert Camfield and Bruce Chapman
Christensen Associates Energy Consulting

September 3, 2024

SECTION I: INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) is revising its Utility tariff under which wholesale generation and transmission (G&T) services are provided to Newfoundland Power (NP). The current tariff consists of two energy blocks (Tier 1 and Tier 2) with a tier boundary that varies by season, complemented by a demand charge. This structure has been in place for some time. Demand charges cover a share of capacity-related costs and are set according to annual peak loads and billed monthly. Energy charges cover the broad array of G&T costs associated with electricity supply, including both capacity- and energy-related costs. Credits recognize NP's own generation and curtailable load capabilities.

The proposed tariff revision will, among other changes, set the price of Tier 2 energy—the tail block—at Hydro's marginal cost of energy.[1] The overarching objective of the proposed change in Hydro's Utility tariff for NP is resource efficiency: set marginal prices which better adhere to the underlying worth of resources employed in the provision of G&T services, on the margin.[2] As a consequence, electricity consumers will be more fully informed of resource costs—indeed, avoided costs—and thus better able to balance the net benefits of consumption decisions, conservation, and renewable choice options, compared to the underlying resource costs of electricity.

[1] Marginal cost-based pricing is not new to Hydro. For a number of years, Hydro based the Tier 2 price according to the costs of Bunker C fuels, used at one of Hydro's major generating stations (Holyrood). (Tier 2 prices included other costs as well.) Second, Hydro has implemented a formal methodology for estimation of forward-looking marginal costs of G&T services, where the marginal cost of energy is set on an opportunity cost basis—namely, the net market value of energy sold by Hydro into regional wholesale electricity markets, predominantly New England.

[2] In the context of utility regulation across North America, the more complete umbrella definition would seemingly take account of an essential revenue constraint: set marginal prices equal to marginal costs while ensuring that the overall tariff package covers the total financial costs of providing services.

As proposed, the structure of the revised tariff retains demand charges and tiered energy charges.[3] The key feature of the proposed two-tier tariff is that the energy prices of the second tier are set at or near Hydro's marginal cost of energy, in turn valued at export prices.[4] Since these prices are highly variable, it is essential that Tier Two prices reflect fairly contemporary market conditions and prices. Accordingly, Hydro intends to reset/update Tier 2 prices annually.

Study results presented below provide support for our findings on three outstanding issues associated with the proposed changes to Hydro's wholesale tariff under which NP takes service:

- Viability and institutional fit of the proposed approach—which calls for Tier 2 prices to be updated annually—within Hydro's current regulatory compact, including deferral accounting, to reconcile *actuals* to allowed sales and revenues set by the Public Utilities Board of Newfoundland and Labrador (Board).
- Working mechanics of the newly proposed tariff for Newfoundland Power, ensuring that:
  - Total revenues realized under the new tariff design under consideration closely approximate the share of Hydro's total cost of service, originally set during the 2017 GRA with a 2019 test year for rate setting.
  - The process of updating Tier 2 energy prices—i.e., marginal energy cost-based prices—is feasible within the context of regulation, and institutionally sustainable over the long term.
- Analytical basis for determining Tier 2 energy charges.

The report content is presented in the following sections:

Section II: *Proposed Working Mechanics of Two-Tier Tariff;*

Section III: *Merits of Annual Updates to Tariff Prices*;

Section IV: *Billing Determinants for Newfoundland Power*;

Section V: *Marginal Costs of Providing G&T Services to Newfoundland Power*;

Section VI: *Assessment of Wholesale Marginal Energy Prices;*

Section VII: *Projections of Marginal Energy Costs (Export Prices)*;

Section VIII: *Integrating Export Prices into a Two-Tier Tariff Framework*; and,

Section IX: *Concluding Comments*

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[3] Hydro proposes that the boundary separating the first and second energy pricing tiers be differentiated according to calendar quarters. Hydro proposes that Tier 2 prices be differentiated by season, with seasons defined as winter (December to March) and non-winter (the remainder). These definitions differ from the current boundary definition (November to April).

[4] Recently installed HVDC facilities including Maritime Link and Labrador Island Link integrate Hydro's Island Interconnected System (IIS) into the Eastern Interconnection transmission grid.

SECTION II: PROPOSED WORKING MECHANICS OF TWO-TIER TARIFF

The starting point for the proposed two-tier tariff is the current tariff approach which is a conventional two-term (demand, energy) tariff structure. The current tariff is subject to regulation by the Board and has been in place for some time. The structure of the proposed two-tier approach adheres to the current tariff in two respects. First, billing determinants used to set prices, including demand charges based on peak loads, set annually, and monthly metered energy for a defined consecutive 12-month period, remain unchanged. Second, importantly, the realization of total revenues under the two-tiered approach is equal to—or closely approximates—revenue flows under the current two-term tariff.

The derivation of prices for the two-tiered tariff is as follows:

$$R_A = \sum_{M=1}^{12} R_M \qquad 1)$$

$$R_M = R_{Tier\ 1}^{monthly\ energy} + R_{Tier\ 2}^{monthly\ energy} + R^{demand\ charges} \qquad 2)$$

$$R_{Tier\ 1}^{monthly\ energy} = R_M - R_{Tier\ 2}^{monthly\ energy} - R^{demand\ charges} \qquad 3)$$

with terms described as follows:

(<u>revenue flows</u>)

$R_A = annual\ revenue\ requirements$

$R_M = monthly\ revenue$

$R_{Tier\ 1}^{monthly\ energy} = P_{Tier\ 1}^{energy} * Energy_{Tier\ 1}$

$R_{Tier\ 2}^{monthly\ tier\ 2\ energy} = P_{Tier\ 2}^{marginal\ energy\ cost} * Energy_{Tier\ 2}$

$R^{demand\ charges} = Demand\ charge_{Month} * Load_{Peak}$

(<u>price terms</u>)

$P_{Tier\ 1}^{energy} = price\ of\ billed\ energy, Tier\ 1$

$\quad = R_{Tier\ 1}^{monthly\ energy} / Energy_{Tier\ 1}$

$P_{Tier\ 2}^{marginal\ energy\ cost} = marginal\ energy\ cost\ basis\ for\ price\ for\ billed\ energy, Tier\ 2$

$D.Charge_{Month} = monthly\ demand\ charge$

(<u>billing determinants</u>)

$Energy_{Tier\ 1}, Energy_{Tier\ 2} = billed\ energy, Tiers\ 1\ and\ 2$

$Load_{Peak} = annual\ peak\ load$

Important points about Hydro's proposed two-tier tariff structure are as follows:

- Revenue flows under the three price terms total to Hydro's annual revenue requirements (R_A) for Newfoundland Power, as shown in equation 1.

- Monthly Tier 1 energy revenue ($R_{Tier\ 1}^{monthly\ energy}$) is equal to the residual of monthly revenue (R_M) minus revenues realized from monthly Tier 2 energy ($R_{Tier\ 2}^{monthly\ \ energy}$) and demand charges ($R^{demand\ charges}$), as shown in equations 2 and 3.

Revenue requirements are based on cost allocation procedures agreed to by participating parties and set under the relevant rules of the Board, given observed and normalized billing determinants.[5]

The above mechanics are straightforward, workable procedures. An outstanding issue is a major focus of this report: how best to determine the marginal energy costs (export prices) applicable to Tier 2 billing determinants…essentially, how should marginal energy costs be determined? In view of the wide variation in marginal energy costs across months and years, Hydro should consider resetting Tier 2 energy prices at least annually, with updated prices effective for the prospective year. If activated annually, the reset procedure might best be carried out during late fall, with regulatory approval for updated prices for the two-tier tariff reached prior to the billing periods during the year following and effective January 1.

SECTION III: MERITS OF ANNUAL UPDATES TO TARIFF PRICES

<u>THE ISSUE: CHANGING RATES BETWEEN GRA PROCEEDINGS</u>: Under the proposed Two-Tier tariff, Tier 2 prices will be updated annually, with updates taking place between General Rate Applications (GRAs). The direct inclusion of marginal costs within the proposed Two-Tier tariff introduces important efficiency properties. However, updating Tier 2 prices annually introduces a certain complication as a matter of regulatory procedure: changing tariff rates between Hydro's GRAs. Indeed, Tier 2 prices based on marginal energy costs/export prices can have large variation, one year to the next, as discussed below at some length in Section V.

<u>DISCUSSION, PRECEDENTS, COMMON PRACTICES</u>: Changing rates between GRAs is not altogether new for Hydro, and common utility practice. To manage the issue of Tier 2 price variation year-on-year, Hydro has considerable regulatory precedent to draw upon for guidance. Mechanisms to change (or adjust) the overall price level between GRAs have been in place for some time, including: 1) the Rate Stabilization Plan (RSP) and 2) deferral accounting procedures selectively applied to defined cost elements of the overall cost of service (COS). Under Hydro's RSP, RSP prices were updated annually to reflect discrepancies between actual and forecasted quantities and prices. As a result, annual imbalances between fuel costs and revenues were limited; RSP mitigated sizable impacts of fuel cost changes on the overall price from one year to another, while ensuring recovery of exogenously determined fuel costs in revenues.

More broadly, frequent updates to tariff rates are commonly accepted regulatory practice. At most utilities, rate riders are used to recover cost shortfalls or dispense revenue surpluses, with prices changing regularly in accordance with predetermined formulas. However, rate riders are highly specific to defined cost categories, and can be specific to defined rate classes, with some

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[5] Billing determinants generally reflect historical electricity purchases adjusted for expected weather, ongoing sales growth, and other anticipated conditions relevant to a projected test year period.

classes either exempt or where individual customers have opt-out tariff options. Selected examples of tariffs and tariff riders with annual updates are as follows:

- Internal cost expenditures associated with energy conservation programs in retail markets, which are common across North America;
- Expenditures associated with the construction of vital new G&T facilities (e.g., Appalachian Power's construction of a new natural gas-fueled generating station);
- Affordability surcharges associated with credits applied to electric bills of low-income households;
- Costs associated with mandated renewable energy facilities (e.g., Renewable Development Fund Rider, Xcel Energy);
- Costs associated with the investment for reinforcement of transmission and distribution facilities (e.g., Storm Hardening in the State of Florida); and,
- Annual updates to the charges within Open Access Transmission Tariffs for the wholesale transmission services provided by incumbent utilities and privately-funded transmission companies, under the Formula Rates procedures of the Federal Energy Regulatory Commission.

<u>VIABILITY OF PRICE CHANGE BETWEEN GRAs</u>: The benefits of annual updates to Tier 2 prices, to Hydro and Newfoundland Power, can be substantial. First, annual updates mitigate the buildup of potential revenue shortfalls or overruns that would be processed through a deferral account. Second, generally speaking, annual updates will better match Tier 2 prices to resource costs (marginal costs). To the extent that the marginal prices in retail markets of Newfoundland Power conform to Tier 2 energy prices, the potential gains in resource efficiency are available. Since its General Service tariffs make use of block designs, timely updates may benefit retail customers as well.[6]

More generally, the block design of the Utility rate acts to segment recovery of required revenues through the first block and coverage of marginal costs through the second block. On a forecast basis at least, the energy price applied to first block usage, combined with the demand charge, covers class-based fixed costs as developed in the cost-of-service study. The second block price recovers forecasted marginal cost applied to actual loads in excess of the first block, among other costs, if desired by Hydro. Generally speaking, as loads vary from forecast, costs and revenues move similarly. Providing seasonal, as opposed to annual, second block prices, and updating them periodically by prior agreement with the regulator should significantly reduce deferred payments/credits.

Newfoundland Power may not necessarily interpret regularly changing Tier 1 and Tier 2 prices as advantageous, since the process may appear to introduce variability into its own revenue recovery. However, this concern is parallel to the familiar concerns that customers have about riders: more frequent revision of the rider price increases the frequency of price changes but also reduces its amplitude. The absence of price adjustments between rate applications could increase the size of deferral account swings.

[6] NP customers receive the benefits of rate mitigation but updating of prices might induce customers to adjust consumption. Price increases would modestly reduce consumption while price reductions would facilitate modest increases in consumption.

SECTION IV: BILLING DETERMINANTS FOR NEWFOUNDLAND POWER

Newfoundland Power's historical load profiles (billing determinants) have strong yet highly consistent seasonality year-over-year, with retail peak loads driven predominantly by the winter heating loads of NP's residential and general service customers. Summarized below are NP's monthly energy injections into its distribution network including purchases from Hydro and internal production.

Table 1: Newfoundland Power's Monthly Energy Purchases and Production[7] (MWh)

	2021	2022	2023
Jan	689,141	733,578	711,176
Feb	649,294	670,590	749,713
Mar	651,181	699,733	715,938
Apr	539,130	565,630	595,278
May	464,108	458,954	499,426
Jun	345,967	369,219	408,240
Jul	337,272	326,385	345,206
Aug	318,229	327,618	330,855
Sep	321,293	325,242	335,191
Oct	445,963	382,335	421,013
Nov	506,195	571,050	596,484
Dec	701,208	678,508	682,458

Total Energy Purchases and Production, 2021-23 (MWh)

	2021	2022	2023
MWh, 2021_23	5,968,981	6,108,841	6,390,978

NP's monthly peak loads follow accordingly, as summarized in Table 2, below.

(see following page)

[7] Monthly load data supplied by Hydro from the AVEVA PI Server. Data may contain small variances from that which was gathered and released by Newfoundland Power to Hydro, using revenue metering data.

Table 2: Newfoundland Power's Monthly Peak Loads (MW)

	2021	2022	2023
Jan	1,168	1,324	1,329
Feb	1,276	1,357	1,500
Mar	1,149	1,303	1,435
Apr	986	1,011	1,087
May	836	824	954
Jun	767	791	785
Jul	621	557	585
Aug	543	558	559
Sep	608	593	654
Oct	840	716	861
Nov	950	1,224	1,063
Dec	1,261	1,282	1,195
Summary of Hourly Loads (MW)			
Max	1,276	1,357	1,500
Min	233	310	316
Average	681	697	730

For these contemporary years, three observations are worth noting:

- energy purchases and peak loads are highly seasonal, with maximum loads recorded in the four winter months and minimum peaks taking place during July and August;
- NP's peak load metrics (average, maximum, and minimum) all rise consistently over these recent years; and,
- seasonal and annual peak loads for the three years are reached in February.

Load factors (LFs) follow accordingly though, somewhat surprisingly, LFs associated with NP's contemporary energy purchases are remarkably similar across months, seasons, and years, as shown in Table 3, below.

(see following page)

Table 3: Newfoundland Power's Monthly Load Factors

	2021	2022	2023
Jan	0.79	0.74	0.72
Feb	0.76	0.74	0.74
Mar	0.76	0.72	0.67
Apr	0.76	0.78	0.76
May	0.75	0.75	0.70
Jun	0.63	0.65	0.72
Jul	0.73	0.79	0.79
Aug	0.79	0.79	0.79
Sep	0.73	0.76	0.71
Oct	0.71	0.72	0.66
Nov	0.74	0.65	0.78
Dec	0.75	0.71	0.77
Summary of Monthly Load Factors			
Max	0.79	0.79	0.79
Min	0.63	0.65	0.66
Average	0.71	0.72	0.73

In fact, for these contemporary years, the ratios of NP's peak loads to energy purchases for winter (December-March) and summer (June-September) are virtually equivalent. The similarity of load factors across years and months affirms the cost analysis: going forward Hydro can depend on Tier 2 prices to accurately capture the marginal cost to serve, provided that market prices are forecast properly. That is, forecast prices reflect expected values: differences in marginal cost to serve from one year to the next are exclusively a result of changes in export prices, not changes in load shapes. Furthermore, the fairly uniform level of load factor across months provides a useful benchmark for setting the Tier 1-2 quarterly boundaries: there is "headroom" to use different boundaries while also ensuring that large shares of hourly loads—though certainly not all—are priced at Tier 2 prices, on the margin. Implicitly, heating loads and non-heating loads have approximately the same load factor. This second point may be useful to Newfoundland Power in setting retail tariff prices.

SECTION V: MARGINAL COSTS OF PROVIDING G&T SERVICES TO NEWFOUNDLAND POWER

<u>DEFINITION</u>: Hydro's marginal costs of generation and transmission services, by definition, are the load-related costs incurred by Hydro, on the margin, in the provision of G&T services provided to retail and wholesale consumers. Further, Hydro's marginal costs of energy, operating reserves, and capacity are *all-in*, covering the entirety of G&T cost elements including carrying charges on investment in G&T facilities, fixed and variable operations and maintenance expenses, capacity charges and line losses on regional transmission paths, fuel inventory, administration and general expenses, working capital, property taxes (where relevant), and insurance.

For Hydro, the methodology underlying marginal energy cost estimation assumes an opportunity cost approach, with energy costs set according to projections of hourly energy prices realized in regional wholesale electricity markets, often referred to by Hydro as export prices. On the other hand, estimates of G&T capacity costs are internal to Hydro's power system. Marginal costs are estimated in hourly frequency and are highly specific to load level, ranging from less than $20/MWh during low-load overnight hours, to well over $1,000/MWh during the very high peak loads experienced during winter seasons.

MARGINAL COST TO SERVE NEWFOUNDLAND POWER: As a matter of first-order approximation, estimates of marginal energy and capacity costs are highly specific to timeframe and are equivalent for all loads served. However, to the extent that the load profiles of Hydro's customers vary, Hydro may incur higher marginal costs, averaged over the year or over seasons, to provide G&T services to some customers than others.

Estimates of Hydro's marginal costs to serve Newfoundland Power are presented below for energy (Tables 4 and 5). Marginal costs of energy are based on Hydro's early-2024 projections of export prices at the Salisbury hub adjusted for transmission path charges for 2025, and Newfoundland Power loads for 2021, 2022 and 2023.[8]

Table 4: Marginal Costs of Energy, Monthly (CAD/MWh)

Load Year	2021	2022	2023
Jan	125.57	126.76	128.35
Feb	103.84	102.87	102.31
Mar	62.81	62.49	62.01
Apr	28.61	28.66	28.30
May	23.40	23.09	23.19
Jun	28.50	28.12	27.92
Jul	44.91	45.32	45.47
Aug	38.71	39.21	38.81
Sep	26.49	26.39	26.67
Oct	25.33	25.17	25.15
Nov	52.60	52.32	52.59
Dec	97.42	94.99	94.28
Weighted Average	**54.67**	**54.45**	**54.42**

(see following page)

[8] Transmission path charges reflect OATT-based reservation charges and line losses (stated as average losses) of the transmission interconnection between Hydro's Island Interconnected System (IIS) and New England's regional wholesale electricity market and including the Maritime Link (HVDC) and transmission networks of Nova Scotia Power and NB Power.

Table 5: Marginal Costs of Energy, for Winter and Non-Winter Seasons (CAD/MWh)

Load Year	2021	2022	2023
4-Month Winter			
Winter (Dec-Mar)	97.25	96.63	96.60
Non-Winter (Apr-Nov)	33.56	33.53	33.51
Weighted Average	**54.67**	**54.45**	**54.42**
6-Month Winter			
Winter (Nov-Apr)	78.47	78.02	77.99
Non-Winter (May-Oct)	31.26	31.26	31.24
Weighted Average	**54.67**	**54.45**	**54.42**

For illustrative purposes only, presented below are Hydro's estimates of marginal cost using costs of energy stated on an *all-in* basis and thus inclusive of marginal energy costs (export prices) plus operating reserves,[9] and capacity costs associated with generation and transmission services. These tables are comparable with Tables 4 and 5 in that the results are based on Hydro's early-2024 projections of export prices at the Salisbury hub for 2025 and Newfoundland Power loads for 2021, 2022 and 2023,

Table 6: Marginal Costs of Energy/Reserve and G&T Capacity, Monthly (CAD/MWh)

Load Year	2021	2022	2023
Jan	301.09	303.83	311.24
Feb	212.90	211.59	208.14
Mar	116.12	116.68	115.89
Apr	39.81	40.05	39.63
May	24.92	24.60	24.70
Jun	30.12	29.75	29.51
Jul	47.03	47.47	47.63
Aug	40.32	40.84	40.42
Sep	27.71	27.59	27.90
Oct	26.96	26.74	26.77
Nov	65.69	66.17	65.83
Dec	210.81	214.26	208.80
Weighted Average	**94.92**	**95.45**	**95.21**

[9] Export prices and estimates of operating reserves are inclusive of transmission path charges.

Table 7: Marginal Costs of Energy/Reserve and G&T Capacity, Winter and Non-Winter Seasons (CAD/MWh)

Load Year	2021	2022	2023
4-Month Winter			
Winter (Dec-Mar)	210.16	211.59	211.09
Non-Winter (Apr-Nov)	37.77	37.85	37.75
Weighted Average	**94.92**	**95.45**	**95.21**
6-Month Winter			
Winter (Nov-Apr)	157.98	159.06	158.59
Non-Winter (May-Oct)	32.89	32.88	32.87
Weighted Average	**94.92**	**95.45**	**95.21**

As revealed by the differences in cost magnitudes between Tables 4/5 and Tables 6/7, Hydro incurs significant G&T capacity costs to serve Newfoundland Power on the margin, estimated in the amount of $39/MWh for 2025. Stated on a kW basis, marginal G&T capacity costs to serve NP approximate $310/kW-year. We encourage Hydro and Newfoundland Power to consider setting demand charges at significantly higher levels in the near future, thus reducing the sizable gap between current charges ($5/kW-month) and Hydro's marginal costs of G&T capacity. Higher demand charges also reduce Tier 1 energy prices.

SECTION VI: ASSESSMENT OF WHOLESALE MARGINAL ENERGY PRICES

As mentioned above, under the opportunity cost approach, wholesale electricity market prices in the New England region serve as the basis for Hydro's marginal energy costs, often referred to as export prices. Hydro exports significant quantities of electricity energy into New England markets and other regional markets in the Northeast with interconnections to New England.

As with other U.S. ISO/RTOs, the paradigm for determining export prices is locational marginal pricing (LMP), where prices are determined for specific commercial locations across the regional market footprint and determined in hourly frequency for both forward (day-ahead) and real-time markets. As a practical matter, Hydro's export prices are based on forward LMPs for the Salisbury hub and the New England market. Northeast electricity markets share a common feature with regional wholesale electricity markets elsewhere: driven by variation in fossil fuel prices and seasonal yet intermittent random capacity constraints, considerable price variation is experienced across days, months, and years. This issue is significant for Hydro's proposed Two-Tier pricing: setting the 2nd Tier energy price may harbor considerable volatility.

The starting point for addressing the issue is the observed historical experience for Salisbury day-ahead energy prices for January 2017-June 2024, observed in hourly frequency. Shown in real terms, Salisbury energy prices are summarized below.

Table 8: Average Hourly Energy Prices for Salisbury Interconnection, $/MWh ('24 USD)

Month	2017	2018	2019	2020	2021	2022	2023	2024
Jan	30.79	78.96	45.61	22.24	36.48	128.24	46.51	65.62
Feb	23.61	29.70	28.67	19.75	62.69	104.93	65.10	36.02
Mar	27.86	26.45	30.83	14.42	28.97	57.76	31.74	23.18
Apr	21.72	26.02	21.46	14.94	20.20	49.46	26.63	24.02
May	18.69	14.07	19.61	12.88	20.68	65.93	23.17	24.75
Jun	18.71	21.06	18.10	16.40	30.77	60.79	30.61	33.25
Jul	21.09	26.00	23.69	19.98	30.92	80.05	38.91	
Aug	19.03	31.27	21.11	20.25	42.18	85.78	24.89	
Sep	18.84	26.08	16.83	17.97	38.72	58.45	27.93	
Oct	22.63	25.72	17.38	20.77	41.97	46.93	24.92	
Nov	24.57	40.85	25.46	21.10	48.05	54.07	36.64	
Dec	53.95	37.37	32.81	32.89	56.86	96.08	35.10	

It is also useful to report variation in the monthly prices for Salisbury, as shown above, in percentage terms and measured as absolute values, as presented below.

Table 9: Absolute Value of % Change in Monthly Prices from Previous Year

Month	2018	2019	2020	2021	2022*	2023	2024	Average
Jan	156%	42%	51%	64%	252%	64%	41%	96%
Feb	26%	3%	31%	217%	67%	38%	45%	61%
Mar	5%	17%	53%	101%	99%	45%	27%	50%
Apr	20%	18%	30%	35%	145%	46%	10%	43%
May	25%	39%	34%	61%	219%	65%	7%	64%
Jun	13%	14%	9%	88%	98%	50%	9%	40%
Jul	23%	9%	16%	55%	159%	51%		52%
Aug	64%	32%	4%	108%	103%	71%		64%
Sep	38%	35%	7%	115%	51%	52%		50%
Oct	14%	32%	20%	102%	12%	47%		38%
Nov	66%	38%	17%	128%	13%	32%		49%
Dec	31%	12%	0%	73%	69%	63%		41%

Within months, high hourly energy prices can reach an order of magnitude above average prices for the month. Similar to Table 8, Table 10 presents the maximum hourly prices for each month across years. The maximum hourly price across years is highlighted for each month, with the bulk of the maximum prices having occurred in 2022 and 2023. Note that the highlighted prices are significantly larger than the averages of Table 8.

Table 10: Maximum Hourly Prices for Months, for Salisbury Interconnection, $/MWh ('24 USD)

Month	2017	2018	2019	2020	2021	2022	2023	2024	Average	Maximum
Jan	78.88	240.13	133.15	61.61	98.88	232.16	123.87	218.29	148.37	240.13
Feb	53.64	82.05	64.36	36.54	137.71	252.71	302.26	84.66	126.74	302.26
Mar	76.78	74.69	84.40	29.07	80.69	223.58	97.68	53.67	90.07	223.58
Apr	45.29	80.10	50.26	26.24	42.22	90.00	54.25	47.54	54.49	90.00
May	71.90	36.14	34.82	25.28	40.23	190.29	44.92	59.42	62.87	190.29
Jun	62.97	60.36	29.82	34.98	148.72	113.69	94.94	310.27	106.97	310.27
Jul	75.64	76.38	59.10	79.61	77.70	315.15	193.98		125.37	315.15
Aug	52.63	142.11	50.60	64.23	143.59	286.81	39.57		111.36	286.81
Sep	77.94	88.68	35.92	46.17	70.87	98.55	180.71		85.55	180.71
Oct	76.88	60.76	104.52	58.08	83.19	125.71	62.29		81.63	125.71
Nov	74.26	147.08	59.30	73.71	104.30	201.99	148.69		115.62	201.99
Dec	181.86	94.34	121.65	129.85	169.64	330.90	163.61		170.27	330.90

As presented below, higher load levels contribute to price variation, measured by the coefficient of variation (CoV).[10]

Table 11: Across-Year Assessment of Monthly Salisbury Price Variation

Month	Average	Variation	Coefficient of Variation
Jan	56.81	34.20	0.60
Feb	46.31	29.21	0.63
Mar	30.15	12.43	0.41
Apr	25.56	10.34	0.40
May	24.97	17.04	0.68
Jun	28.71	14.54	0.51
Jul	34.38	21.16	0.62
Aug	34.93	23.85	0.68
Sep	29.26	14.97	0.51
Oct	28.62	11.25	0.39
Nov	35.82	12.64	0.35
Dec	49.29	22.92	0.47

Comparatively high CoV values for July and August are similar in magnitude to those of the high-load winter months while the CoVs of the average non-winter month prices are lower, significantly. (The high CoV for the month of May (0.68), an off-peak month, reflects anomalous price experience. The average and maximum prices of May 2020 are very low and those for May 2022 are abnormally high).[11]

By inspection, higher prices are generally observed during the winter months, December through March, and particularly during January. In addition, the high prices during the hot summer (July,

[10] The coefficient of variation is the ratio of the standard deviation to the average and serves as a basis of normalization facilitating the comparison of variation across sample periods.

[11] Variation metrics such as standard deviation statistics are highly specific to frequency. In the case of June 2024, hourly Salisbury prices rose dramatically during the late afternoons of June 18-21.

August) of 2022 reflect exceptional worldwide natural gas prices,[12] and reveal the presence of natural gas-fueled resources on the margin, in New England and elsewhere.

The pronounced year-over-year variation in Salisbury prices—New England wholesale market locations reveal high hourly variation on most days, regardless of season—is generally similar for all months of each year, as shown above in tables 8 through 11.

In summary, wholesale market energy prices for the Salisbury interconnection, which along with export quantities is an essential driver for determining Hydro's export revenues, reveal considerable price variation across hours, months, and years.

SECTION VII: PROJECTIONS OF MARGINAL ENERGY COSTS (EXPORT PRICES)

METHODOLOGY: Generally speaking, projections of wholesale electricity market prices can be approached in three ways including:

1. Large-scale market simulation tools;
2. Statistical analyses, including estimated structural models and time-series methods; and,
3. Observed futures prices for regional electricity market hubs with sufficient transaction liquidity.

Over projection periods including near-term and long-term timeframes market simulation tools estimate electricity demand and supply functions. For regional markets, electricity demand is a function of the path of economic activity, temperature (and potentially other weather characteristics), electricity prices, and demand-side technologies including renewable resources. The electricity supply function takes account of supply technologies inherent to the regional portfolio of generation, fuel costs, and G&T supply constraints where relevant. Typically, model runs simulate prices in hourly frequency or peak and off-peak periods by month.

Statistical analyses are estimated over historical periods and are operative, typically, in monthly frequency—or for the commercially-defined peak and off-peak hourly periods of months—and take general account of demand and supply including weather, fuel costs, and anomalous market events within the historical data set.

Observed futures prices are posted on energy markets operated by commodity exchange services such as the Chicago Mercantile Exchange (CME) and the International Commodity Exchange (ICE). Futures are commodity contracts with a common set of commercial and non-commercial terms, as set by commodity exchanges. For defined commodities, market

[12] The critical event was the unexpected interruption of natural gas supply into Western Europe from the East during the summer of 2022, in turn a result of the Russian-Ukraine conflict.

participants[13] buy and sell futures contracts in order to hedge—i.e., "lock in"—prices for specified timeframes and delivery locations. As an example, a futures contract may be specified as a 5 MW daily peak period for delivery in February 2025 at the PJM West hub.

HYDRO'S APPROACH: Hydro is a market participant within New England regional electricity markets and also engages in wholesale power transactions across Canada's eastern provinces. Hydro's active engagement in wholesale markets requires the assessment of day-ahead and near-term market conditions; as well as an extended outlook which inherently takes account of future electricity supply, including the evolution in generation technology in the region such as the siting of renewable resources and prices—and availability—of primary fuels. For the near term, Hydro employs market futures contracts (method 3) listed on commodity exchanges as the primary means to assess the near-term outlook. Settled futures prices reflect the expectations of energy market traders, including the trading activities of incumbent utilities and independent energy companies to hedge price risks, and financial services organization engaging in speculation. Futures prices implicitly capture expectations of the weather impact on electricity demands, unit availability of individual generator units that together comprise regional generation supply, and power imports from other regions.

Hydro's long-term market outlook—i.e., electricity price forecast—is based on published forecasts prepared by energy service organizations which, in turn, utilize large-scale simulation tools (method 1). Generally speaking, these tools take into account the long-term path for regional electricity demand, retirements of fossil fuel generators, availability and random forced outages of generating units, projections of fossil fuel prices and gas pipeline throughput constraints, and future power supply provided by renewable sources. In brief, Hydro's projections of export prices closely focus on regional markets and are integral to Hydro's official projections of marginal costs of energy and capacity for G&T services, filed periodically with the Board.

In view of the above, we recommend that Hydro's approach, market-based futures prices over the near-term, be used as the basis for setting Tier 2 prices of the proposed Two-Tier tariff for Newfoundland Power. Moreover, futures prices are core to Hydro's near-term estimates of marginal cost for the IIS, and thus take account of locational basis differences for the Salisbury hub, expected CAD/USD exchange rates, and transmission path charges. The application of futures prices as the basis for determining market value of energy over the near-term period is commonly accepted practice across wholesale markets and widely used by electricity service providers. For these immediate purposes, Tier 2 prices should be based on Hydro's projections of export prices in isolation of operating reserves.

Presented below are projections of export prices for 2025, for months and seasons. For Tier 2 prices of the proposed Two-Tier tariff for Newfoundland Power, we recommend that Hydro and Newfoundland Power differentiate Tier 2 prices on a seasonal basis.

[13] Market participants (commodity traders) must be registered with the Commodity Futures Trading Commission (CFTC). On behalf of the CFTC, the National Futures Associates (NFA) carries out the registration of traders and intermediaries including commodity brokers, which carry out much of the trading activities on commodity exchanges for market participants/traders.

Table 14: Export Prices for the Salisbury Hub inclusive of Path Charges (CAD/MWh)[14]

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
125.67	102.07	62.10	27.81	22.54	27.22	42.32	36.19	24.55	24.18	50.89	94.57
							Winter			Non-Winter	
							96.98			33.54	
							Projected Salisbury Export Prices for 2025:				54.51

We anticipate that Tier 2 prices will be updated annually in order to reflect the contemporary market outlook for the following year in which the prices of the two-tier tariff are effective.

SECTION VIII INTEGRATING EXPORT PRICES INTO A TWO-TIER TARIFF FRAMEWORK

As described in Section II, determining terms for the proposed Two-Tier Tariff is straightforward. The process can start by determining the boundary which separates Tier 1 and Tier 2 energy blocks. Tier energy blocks can be determined in accordance with administrative conventions such as quarterly intervals, defined for seasons, or perhaps set as a common Tier 1-2 boundary over calendar months. (For example, if NP favors quarterly values for financial reporting purposes, Hydro's methodology can accommodate such preferences. The key criterion is that in each billing period, electricity consumption by NP's retail customers will reach into Tier 2. Under such circumstances, the Tier 2 price is the effective marginal price which, by definition, is Hydro's change in the cost of energy supply as a result of a change in the level total load served.

Projected export prices, estimated monthly and adjusted for transmission path charges and expected currency exchange rates, should be determined for the seasons defined by the pattern of prices. This pattern of averaging can differ from the pattern of load averaging discussed immediately above. Billing determinants should reflect Newfoundland Power's expected energy and demand purchases during the forward year for which Two-Tier Tariff prices are set.[15]

Expected revenues associated with G&T services provided by Hydro to Newfoundland Power can reflect the applicable tariff prices under which Newfoundland Power takes service and expected billing determinants for the forward year. Based on projected export prices and agreed-to demand charges, expected revenues realized under billing determinants for Tier 2 energy and peak loads are estimated, and then subtracted from total revenue.[16] Based on Tier 1 billing

[14] The seasonal and annual averages of the Salisbury prices for 2025 are based on an hourly price profile, as applied to projections of monthly peak and off-peak prices.

[15] As shown, the seasonal and annual average prices weighted by Newfoundland Power's load profile for years 2021-2023. Not discussed is the conversion of export prices, forecast in monthly frequency, to hourly prices and weighted average Tier 2 prices applicable to Newfoundland Power's load profile. As touched on in Section V, the marginal cost incurred by Hydro to serve Newfoundland Power may differ from that of other customers due to differences in load profiles.

[16] Tier 2 billing determinants and prices will vary as 1) drivers of electricity demand (weather, economic activity) affect total energy purchases by Newfoundland Power; and 2) the year-ahead outlook for Salisbury prices changes.

determinants, Tier 1 energy charges are set at levels which satisfy the remaining share of total revenue (revenue requirements).

Under Hydro's proposed Two-Tier Tariff, Tier 1 prices are equal across all months. Hydro has pricing options in this regard. The common annual Tier 1 price spreads inframarginal costs associated with Tier 1 loads across all months relatively equally. However, since the role of Tier 1 prices is predominantly one of revenue recovery of a lump sum, the pattern could be made more seasonal. For example, the winter price could be set higher than the non-winter price, producing similar pricing patterns between Tier 1 and 2 prices between seasons. (E.g., both seasons would feature declining block pricing, assuming that Tier 2 prices are low enough for this outcome.) Moreover, Newfoundland Power may harbor preferences with respect to Tier 1 pricing based on internal cash needs.

Strawman prices obtained from the process described in Section II are presented below, where estimated energy prices under Hydro's proposed Two-Tier Tariff are specific to forecast year 2025. The strawman prices adhere to hold harmless criteria (revenue neutrality). Once Tier 2 prices are set, demand charges determine Tier 1 prices: higher (lower) demand charges decrease (increase) Tier 1 energy prices.

Table 15: Demand and Energy Prices Under Proposed Two-Tier Tariff, 2025

Billing Determinants	Winter	Non-Winter	**Tariff Prices**	Winter	Non-Winter	**Revenue (000's CAD)**	Winter	Non-Winter
Peak Demand	1,393	1,393	Demand Charge			Demand Charges	$27,855	$55,710
			(CAD $/kW-month)	$5.00	$5.00			
Energy (GWh)			Energy Charges			Energy Charges		
Tier 1	2,139	2,501	Tier 1 Prices* ($/MWh)	$75.54	$75.54	Tier 1	$161,585	$188,945
Tier 2	535	625	Tier 2 Prices ($/MWh)	$96.98	$33.54	Tier 2	$51,862	$20,973
Total	2,674	3,127				Total	$213,447	$209,918
1-2 Tier Boundary	0.80	0.80	**Annual Revenue**			Total	$241,302	$265,628
			Requirements (000's):	**$506,929**			Total:	**$506,929**
* As derived								

An essential result is revenue sufficiency and neutrality: projected revenues under defined billing determinants match cost of service-based revenue requirements. The Two-Tier Tariff can obtain revenue neutrality in two ways: First, Tier 1 energy prices are adjusted annually at the time that Tier 2 energy prices are updated. Second, differences between actual and forecast revenues are bundled into deferral accounts.

A third approach locks in projected Tier 1 billing determinants and prices over near-term years, for perhaps 2-3 years ahead, thus ensuring that pricing incentives inherent to Tier 2 are fully operative. This third approach serves as a form of price hedge for Tier 1 energy, covering a substantial share of revenue flows for both Hydro and Newfoundland Power. Much like Hydro's approach, this approach also preserves the full benefits of marginal cost-based price incentives for Newfoundland Power and its retail customers.

SECTION IX: CONCLUDING COMMENTS

Hydro's proposed revised Utility tariff featuring marginal cost-based seasonal Tier 2 prices, coupled with annual updates, is in keeping with Hydro's long-term strategy of setting economic cost-based prices and thus accounting for the G&T resources employed in the provision of G&T

services across the province, on the margin. Additionally, industrywide evidence indicates that periodic changes in prices according to established formulations are common, as seen by the many forms of riders that are regularly updated.

The proposed revision to Hydro's utility tariff structure accommodates and retains current precedents, and blends in forward-looking pricing provisions, including:

- Retention of the overall block design of the current tariff and associated contractual relationships between Hydro and Newfoundland Power.
- Retention—but with modifications—of the seasonal definition of Tier 1-Tier 2 energy boundaries.
- Modification of Tier 2 prices from an annual to a seasonal definition. The seasonal pattern of Tier 2 prices is essential in view of the strong seasonal pattern in Hydro's marginal energy costs, as well as G&T capacity costs.
- Development of seasonal Tier 2 prices based on projections of export prices weighted by NP's load profile.
    - Hydro's current projections of export prices yield 2025 Tier 2 prices of \$96.98/MWh and \$33.54/MWh for the winter and non-winter seasons, respectively.
- Retention of the demand charge structure and the commercial and non-commercial business agreement currently in place between Hydro and Newfoundland Power, including:
    - Demand charges determined according to annual peak loads but billed monthly;
    - Credits for NP-owned generation and curtailable services;
    - Non-commercial terms and related details.
- Annual updates of the Tier 2 prices based on forecasts by Hydro of marginal costs for the upcoming winter and non-winter seasons. Hydro anticipates updating Tier 2 prices annually using a recent price forecast.
    - A tangential benefit of frequent Tier 2 price updates is that the adjustment of Tier 1 prices is held to narrow bounds, thus ensuring that hold harmless/revenue neutrality criteria are strictly adhered to within time domain.

Our analysis of issues pertaining to Tier 2 prices implies that:

- Systematic, recurring differences in marginal energy costs/export prices across months provide an analytical basis for seasonal Tier 2 pricing.
- As presented in Section V, substantial variation in export prices is revealed by several metrics (means, maximum value, standard deviation) across years and months, and also across hours within months. As a consequence, Hydro should ensure that Tier-Two Tariff prices are updated annually, and possibly allow for within-year updates should special circumstances warrant. Such an approach ensures that marginal prices (Tier 2), as charged, will better match actual marginal energy cost/export prices.

Schedule 2

Schedule of Rates, Rules and Regulations

UTILITY

Availability

This rate is applicable to service to Newfoundland Power ("NP").

Definitions

"Billing Demand"

The Curtailable Credit shall apply to determine the billing demand as an adjustment to the highest Native Load established during the winter period. The computation of the adjustment to reflect the Curtailable Credit is provided in the definitions below.

In the months of January through March, billing demand shall be the greater of:

a) The highest Native Load less the Generation Credit and the Curtailable Credit, beginning in the previous December and ending in the current month; and

b) The Minimum Billing Demand.

In the months of April through December, billing demand shall be the greater of:

a) The Weather-Adjusted Native Load less the Generation Credit and the Curtailable Credit, plus the Weather Adjustment True-up; and

b) The Minimum Billing Demand.

If at the time of establishing its Maximum Native Load, NP has been requested by Hydro to reduce its Native Load by shedding curtailable load, the calculation of Billing Demand for each month shall not deduct the Curtailable Credit.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	83,486
Thermal Generation Credit	34,568
Newfoundland Power Generation Credit	**118,054**

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, NP will be provided with an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

"Curtailable Credit" is determined based upon NP's forecast curtailable load available for the period in accordance with the terms and conditions set forth in NP's Curtailable Service Option. NP will notify Hydro of its available curtailable load with its forecast of annual and monthly electricity requirements.

In order to receive the Curtailable Credit, NP must demonstrate the capability to curtail its customer load requirements to the level of the Curtailable Credit. This will be verified in a test by curtailing load at a minimum of this level for a period of one hour. The test will be carried out at a mutually agreed time in December. If the level is not sustained, the Curtailable Credit will be reduced to the level sustained. If Hydro requests NP to curtail load before a test is completed and NP demonstrates the capability to curtail to the level of the Curtailment Credit, no test will be required.

NP will be required to provide a report to Hydro no later than April 15 to demonstrate the amount of load curtailed for each request of Hydro during the previous winter season. If the load curtailed is less than forecast for either request during the winter season, the annual Curtailable Credit will be adjusted to reflect the average load curtailed for the winter season. If NP is not requested to curtail during the winter season, the Curtailment Credit will be established based upon the lesser of the load reduction achieved in the test or the forecast curtailable load (as provided in the previous two paragraphs).

"Maximum Native Load" means the maximum Native Load of NP in the four-month period beginning in December of the preceding year and ending in March of the current year.

"Minimum Billing Demand" means ninety-nine percent (99%) of:

NP's test year Native Load less the Generation Credit and the Curtailable Credit.

The Curtailable Credit reflected in the Minimum Billing Demand will be set to equal the curtailable load used to determine the Maximum Native Load for NP for the most recently approved Test Year.

"Month" means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

"Native Load" is the sum of:

a) The amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen-minute period thereafter;

b) The total generation by NP averaged over the same fifteen-minute periods.

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load
plus (Weather Adjustment, rounded to 3 decimal places, x 1,000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

a) The greater of:

- The Weather Adjusted Native Load less the Generation Credit and the Curtailable Credit (if applicable), times three; and
- The Minimum Billing Demand, times three; and

b) The sum of the actual billed demands in the Months of January, February and March of the current year.

Monthly Rates

Billing Demand Charge

Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

Demand Charge……………………………………………………………………………$5.00 per kW of Billing Demand

Energy Charge

January-March

First 590,000,000 kilowatt-hours*……………………………………………………………@ 8.515¢ per kWh
All excess kilowatt-hours*………………………………………………………………………@ 9.698¢ per kWh

April-June

First 290,000,000 kilowatt-hours*……………………………………………………………@ 8.515¢ per kWh
All excess kilowatt-hours*………………………………………………………………………@ 3.354¢ per kWh

July-September

First 130,000,000 kilowatt-hours*……………………………………………………………@ 8.515¢ per kWh
All excess kilowatt-hours*………………………………………………………………………@ 3.354¢ per kWh

October-November

First 250,000,000 kilowatt-hours*……………………………………………………………@ 8.515¢ per kWh
All excess kilowatt-hours*………………………………………………………………………@ 3.354¢ per kWh

December

First 250,000,000 kilowatt-hours*……………………………………………………………@ 8.515¢ per kWh
All excess kilowatt-hours*………………………………………………………………………@ 9.698¢ per kWh

Firming-Up Charge

Secondary energy supplied by
Corner Brook Pulp and Paper Limited*……………………………………………………@ 2.882¢ per kWh

RSP Adjustment - Current Plan……………………………………………………………………@ 0.461¢ per kWh

Project Cost Recovery Rider…………………………………………………………………………@ 1.124¢ per kWh

CDM Cost Recovery Adjustment……………………………………………………………………@ 0.017¢ per kWh

***Subject to RSP Adjustment, CDM Cost Recovery Adjustment, and Project Cost Recovery Rider**

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 to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering shall be applied to the metered demand.

Weather Adjustment

This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

a) Weather adjustment shall be undertaken for use in determining NP's Billing Demand.

b) Weather adjustment shall be derived from Hydro's NP native peak demand model.

c) By September 30th of each year, Hydro shall provide NP with an updated weather adjustment coefficient incorporating the latest year of actuals.

d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to weather station data for the St. John's, Gander, and Stephenville airports reported by Environment Canada. NP's regional energy sales shall be used to weigh regional weather data. Hydro shall consult with NP to resolve any circumstances arising from the availability of, or revisions to, weather data from Environment Canada and/or wind chill formulation.

e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding seven hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition of underlying weather data.

f) Subject to the availability of weather data from Environment Canada, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of the Weather-Adjusted Native Load by April 5th of each year.

General

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

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach a mutual agreement, the billing will be based on Hydro's best estimate.

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 Subsection 70(1) of the *Act* for the approval of an update to the wholesale utility rate charged to Newfoundland Power Inc. ("Newfoundland Power"), effective January 1, 2025.

AFFIDAVIT

I, Dana Pope, of St. John's in the province of Newfoundland and Labrador, make oath and say as follows:

1) I am Vice-President, Regulatory Affairs & Stakeholder Relations, Newfoundland and Labrador Hydro, the applicant named in the attached application.

2) I have read and understand the foregoing application.

3) To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this application are true.

SWORN at St. John's in the province of Newfoundland and Labrador this 16th day of September 2024, before me:

~~Commissioner for Oaths~~, Newfoundland and Labrador
A Barrister,

Dana Pope, CPA (CA), MBA