Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

April 16, 2025

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 Approval of a Proposed Long-Term Supply Cost Variance Deferral Account

Enclosed is Newfoundland and Labrador Hydro's ("Hydro") application for approval of a deferral account, modifications to Hydro's Cost of Service Methodology related to the long-term plan for the current Supply Cost Variance Deferral Account ("SCVDA") and an accounting deviation necessary as a result of the amalgamation of Nalcor Energy ("Nalcor") and Hydro.

Hydro's SCVDA was approved by the Board of Commissioners of Public Utilities ("Board") effective November 1, 2021.[1] In its application, Hydro had indicated it would provide additional evidence on a long-term approach to the SCVDA in its next general rate application ("GRA").

In the interest of regulatory efficiency, Hydro is instead submitting an application in advance of its next GRA to establish a new deferral account, the Long-Term SCVDA. Hydro's application also contains proposed Cost of Service allocation methodologies for certain components of the SCVDA that have not previously been addressed, as well as an accounting deviation necessary as a result of the amalgamation of the former Nalcor and Hydro.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

[1] Board Order No's. P.U. 33(2021) and P.U. 4(2022).

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Board General

Consumer Advocate
Dennis M. Browne, KC, Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, KC, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Labrador Interconnected Group
Senwung F. Luk, Olthuis Kleer Townshend LLP
Nicholas E. Kennedy, Olthuis Kleer Townshend LLP

Linde Canada Inc.
Sheryl E. Nisenbaum
Peter Strong

Newfoundland Power Inc.
Dominic J. Foley
Douglas W. Wright
Regulatory Email

Teck Resources Limited
Shawn Kinsella

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Glen G. Seaborn, Poole Althouse

Approval of a Proposed Long-Term Supply Cost Variance Deferral Account

April 16, 2025

An application to the Board of Commissioners of Public Utilities

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 Sections 58, 71, and 80 of the *Act*, for the approval of a deferral account, modifications to Hydro's Cost of Service, and an accounting deviation related to the long-term plan for the current Supply Cost Variance Deferral Account ("SCVDA").

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, 2024*, 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 which relate to that service.

3. In July 2021, Hydro applied for a new deferral account, the SCVDA, to provide a mechanism to deal with rate mitigation funding and rate changes implemented solely to recover Muskrat Falls Project ("Project") costs. The Board approved Hydro's proposals, effective November 1, 2021.[1]

4. In addition to capturing the rate mitigation funding and rate changes noted above, the SCVDA enables the deferral of costs related to Hydro's requirement to make payments under the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA"), and the Transmission Funding Agreement ("TFA") between Labrador-Island Link ("LIL") Partnership and Hydro (collectively the "Project Costs") prior to recovering these costs. The deferral account enables Hydro to isolate

[1] Board Order No's. P.U. 33(2021) and P.U. 4(2022).

the net effect of Project Costs and rate mitigation (and related rate increases) in advance of Hydro's next general rate application ("GRA").

5. The SCVDA also includes variances for costs and revenues from Hydro's approved test year for items such as fuel costs associated with the Holyrood Thermal Generating Station, transmission tariff revenue, net revenues from exports, greenhouse gas credit revenues, load variations, rural rate adjustments, and other Island Interconnected System supply cost variances. The existing SCVDA definition reflects the calculation of financing charges based on Hydro's short-term borrowing costs.

6. To address the disposition of the SCVDA, Hydro proposed to file a future application with the Board, subsequent to receipt of Hydro's next GRA Order, to deal with the allocation and recovery of the balance in the account that had accumulated prior to the conclusion of the GRA.

7. Hydro had noted it would provide additional evidence on a long-term approach to the SCVDA, including a proposed allocation and recovery approach to the deferral account balances that will accumulate subsequent to Project Costs and rate mitigation being reflected in customer rates.

8. Hydro is instead making its proposals at this time regarding the long-term approach to the SCVDA, described within this application, in the interest of regulatory efficiency and to streamline the upcoming GRA.

9. The following proposals address the allocation methodology for transferring monthly variances to the plan balances for Newfoundland Power Inc. and Island Industrial Customers, as well as the finance charges to be applied to the account for the long-term.

10. Hydro will file a separate application to deal with the balance disposition of the proposed Long-Term SCVDA.

B. Application: Long-Term SCVDA

11. Hydro's proposed long-term approach is the creation of a new deferral account called the Long-Term SCVDA which is separate from the existing SCVDA, but with components consistent with the current SCVDA, as well as corresponding allocation methodologies between customer classes.

12. Hydro intends for the existing SCVDA to accumulate costs, revenues and variances from the 2019 Test Year until Hydro's next GRA; after that time, once a new test year is approved, Hydro would utilize the Long-Term SCVDA. Hydro is requesting that the Long-Term SCVDA become effective January 1 of Hydro's next approved test year.

13. Schedule 2 to this application provides the definition and details of the components of the proposed Long-Term SCVDA.

Allocation Methodology

14. Hydro's proposed allocation methodology for the Long-Term SCVDA is closely linked to the allocation methodology approved for costs included in its Cost of Service. Hydro notes that using the allocators in the cost of service to allocate variances from those costs in the Long-Term SCVDA would result in a more accurate allocation of costs between customers. Hydro proposes using the allocators approved for the test year cost of service to classify costs and credits as demand or energy related.

15. Section 2.1 of Schedule 1 to this application provides further discussion of the allocation methodology, with the specific allocation of demand and energy costs outlined in Sections 2.1.1 and 2.1.2.

16. The Cost of Service allocation methodology for the cost and credit components in the Long-Term SCVDA have already been approved, with the exception of three: rate mitigation funding, transmission tariff revenues, and greenhouse gas credit revenues. Hydro's proposals later in this application include proposed cost of service allocation methodologies for those components.

Finance Charges

17. In Hydro's application for the current SCVDA, Hydro proposed to calculate financing charges using approved Weighted Average Cost of Capital ("WACC") given the proposed blending of historical balances from existing deferral accounts with the payments under the Muskrat Falls PPA; however, the Board directed that the calculation of finance charges on the existing SCVDA to be calculated based on Hydro's short-term borrowing costs.

18. Since the establishment of the existing SCVDA, Hydro has implemented a Project Cost Recovery Rider to recover some of the costs in the account from customers, and rate mitigation funding

has been applied or is committed to reduce the balance in the account to zero, in accordance with the Government's rate mitigation plan. Therefore, the SCVDA is currently operating in a similar manner to the long-term approach for any deferral account relating to supply costs, such as the Rate Stabilization Plan ("RSP"), where cost variances are collected annually. This will continue to be the case in the Long-Term SCVDA.

19. These variances and the resulting balance in the Long-Term SCVDA are expected to be much lower in comparison to those in the existing SCVDA, as Project Costs and rate mitigation funding will be included in the Cost of Service and test year revenues in Hydro's next GRA, prior to Long-Term SCVDA becoming effective. Contrary to the existing SCVDA, when it was originally created, balances are not expected to be material and fast-growing, and the Long-Term SCVDA will operate in a similar manner to Hydro's historical deferral accounts relating to supply costs, such as the RSP, where balances in the account are collected annually.

20. For these reasons, and as discussed in Section 2.4 of Schedule 1 to this application, Hydro is proposing that the interest on the Long-Term SCVDA be calculated according to current regulatory practice in Newfoundland, using the WACC as approved in Hydro's test year. The calculation of Finance Charges based on Hydro's test year WACC has been included in the proposed account definition, included as Schedule 2.

C. Application: Cost of Service Methodology

21. As part of defining the Long-Term SCVDA operation, Hydro is proposing to update the Cost of Service Methodology for the consistent treatment of rate mitigation funding, transmission tariff revenue, and greenhouse gas credits revenue.

22. Revisions to Hydro's Cost of Service Methodology for use in the determination of test year class revenue requirements reflecting the inclusion of the Project Costs upon full commissioning were approved, based on a settlement agreement reached among the parties, in Board Order No. P.U. 37(2019).

23. The approved recommendations regarding the Muskrat Falls PPA, TFA and export revenues included:

(i) Power purchase costs resulting from the Muskrat Falls PPA and the TFA shall be functionalized as generation;

(ii) Net export revenues shall be functionalized as generation, which is the same manner as the functionalization of the Project Costs;

(iii) The classification between demand and energy for the power purchase costs resulting from the Muskrat Falls PPA and the TFA shall be based on the system load factor. For greater clarity, it was agreed that this is inclusive of the costs related to the Muskrat Falls Generation, the LIL, and the Labrador Transmission Assets; and

(iv) Net export revenues shall be classified using the system load factor, which is the same manner as the classification of the Project Costs.

24. As Hydro details in Section 2.2 of Schedule 1 to this application, Hydro proposes the application of the principles noted above to other forms of rate mitigation or credits offsetting Project Costs. In particular, Hydro proposes that rate mitigation funding, transmission tariff revenue, and greenhouse gas credits be functionalized as generation and that the classification between demand and energy for each shall be based on the system load factor.

D. Application: International Financial Reporting Standards

25. For regulatory reporting purposes, Hydro adopted International Financial Reporting Standards ("IFRS") as of January 1, 2014, as approved in Board Order No. P.U. 13(2012). Hydro also elected to adopt IFRS 14 — *Regulatory Deferral Accounts* in its initial adoption of IFRS and subsequent financial statements, which permits Hydro to continue to account for regulatory deferral account balances in accordance with Canadian Generally Accepted Accounting Principles. The adoption of IFRS 14 – *Regulatory Deferral Accounts* resulted in changes for financial statement presentation purposes only; there was no impact on ratepayers.

26. Subsequent to the amalgamation of Nalcor Energy and Hydro, effective January 1, 2025, a change to the accounting for rate mitigation funding was required under IFRS. To facilitate the incorporation of rate mitigation funding into Hydro's test year and subsequent reporting, Hydro is also requesting an accounting deviation to allow for the accounting of rate mitigation funding

to remain consistent with that which was in place prior to amalgamation. Further discussion of this issue is provided in Section 2.5 of Schedule 1.

E. Hydro's Requests

27. Hydro requests the Board approve:

(i) The proposed Long-Term SCVDA, for which the account definition is provided in Schedule 2, to become effective on January 1 of Hydro's next approved test year;

(ii) The proposed modifications of Hydro's current Cost of Service Methodology; and

(iii) The proposal to deviate from IFRS, effective January 1, 2025, to allow for the accounting of rate mitigation funding to remain consistent with that which was in place prior to amalgamation, resulting in rate mitigation funding being recognized as revenue.

F. Communications

28. 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 April 2025.

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 685-4973

Schedule 1

Evidence Supporting the Proposed Long-Term Supply Cost Variance Deferral Account

Contents

List of Attachments

1.0 Introduction

Newfoundland and Labrador Hydro's ("Hydro") existing Supply Cost Variance Deferral Account ("SCVDA") was approved by the Board of Commissioners of Public Utilities ("Board"), effective November 1, 2021, in Board Order No's P.U. 33(2021) and P.U. 4(2022). The existing SCVDA enables the deferral of costs related to Hydro's requirement to make payments under the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA"), and the Transmission Funding Agreement ("TFA") between Labrador-Island Link ("LIL") Partnership and Hydro (collectively the "Project Costs") prior to recovering these costs. The deferral account also captures rate mitigation funding and rate changes implemented solely to recover Project Costs to offset charges to Hydro. The deferral account enables Hydro to isolate the net effect of Project Costs and rate mitigation (and related rate increases) in advance of Hydro's next general rate application ("GRA").

The account also includes variances for costs and revenues from Hydro's approved test year for items such as fuel costs associated with the Holyrood Thermal Generating Station ("Holyrood TGS"), transmission tariff revenue, net revenues from exports, greenhouse gas credit revenues, load variations, rural rate adjustments, and other Island Interconnected System supply cost variances. The existing SCVDA definition reflects the calculation of financing charges based on Hydro's short-term borrowing costs.[1]

In Hydro's application for the SCVDA, to address the disposition of the deferral account, Hydro proposed to file a future application with the Board subsequent to the next GRA Order to deal with the allocation and recovery of the balance in the account that had accumulated prior to the conclusion of the GRA.

The application for the existing SCVDA noted that, in its next GRA, Hydro would provide additional evidence on a long-term approach to the SCVDA, including a proposed allocation and recovery approach to the deferral account balances that will accumulate subsequent to Project Costs and rate mitigation being reflected in customer rates. In the interest of regulatory efficiency and to streamline the process for the upcoming GRA, Hydro is working to submit reports and applications to bring resolution to various

[1] Please refer to Schedule A of Board Order No. P.U. 4(2022).

issues and items in advance, wherever possible. One such application is Hydro's proposal for the establishment of a long-term solution to the SCVDA, as further outlined in the evidence below.

1.1 Application

This document details and supports a proposed long-term approach to the SCVDA: a new deferral account, separate from the existing SCVDA, with consistent components and proposed corresponding allocation methodologies between customer classes.

The existing SCVDA will accumulate costs, revenues and variances from the 2019 Test Year until Hydro's next GRA; after that time, once a new test year is approved, Hydro would transition to the Long-Term SCVDA. Hydro will propose the disposition of any balances remaining in the existing SCVDA after the transition to the Long-Term SCVDA in an application following the GRA.

Hydro's proposed allocation methodology for the long-term SCVDA is closely linked to the allocation methodology approved for costs included in its Cost of Service. The Cost of Service allocation methodology for the cost and credit components in the long-term SCVDA have already been approved,[2] with the exception of three: rate mitigation funding, transmission tariff revenues, and greenhouse gas credit revenues. Hydro's proposals in this application include proposed cost of service allocation methodologies for those components.

Subsequent to the amalgamation of Nalcor Energy ("Nalcor") and Hydro, effective January 1, 2025, a change to the accounting for rate mitigation funding was required under International Financial Reporting Standards ("IFRS"). To facilitate the incorporation of rate mitigation funding into Hydro's test year and subsequent reporting, Hydro is also requesting an accounting deviation to allow for the rate mitigation funding to remain consistent with that which was in place prior to amalgamation.

This document includes the following proposals:

- An allocation methodology for transferring monthly variances in all cost and credit components in the Long-Term SCVDA to the plan balances for Newfoundland Power Inc. ("Newfoundland Power") and the Island Industrial Customer ("IIC") class;

[2] Hydro's 2019 Cost of Service Methodology was accepted by the Board as part of Hydro's 2017 GRA, approved in Board Order No. 16(2019).

- Updates to the Cost of Service Methodology to support the allocations of monthly variances for rate mitigation funding, transmission tariff revenues, and greenhouse gas credit revenues;
- A rate for the purpose of calculating finance charges on balances in the Long-Term SCVDA; and
- A request for an accounting deviation related to the accounting of rate mitigation funding, resulting in treatment that is consistent with pre-amalgamation of Nalcor and Hydro legal entities, which will result in recognizing rate mitigation funding as revenue.

Hydro is requesting that the proposed Long-Term SCVDA and the proposals for calculating financing charges and allocation methodology become effective January 1 of Hydro's next approved test year. The approach for disposition or recovery of deferral account balances will be addressed in a future application to the Board, giving consideration to the methodology for updating the wholesale rate that will be the subject of a future application[3] and the Government of Newfoundland and Labrador's ("Government") rate mitigation plan. Hydro proposes that the updates to the cost of service methodology be effective when approved.

2.0 Proposed Long-Term Supply Cost Variance Deferral Account

Hydro's upcoming GRA will incorporate a cost of service, which includes Project Costs and associated rate mitigation. The proposed Long-Term SCVDA will capture variances between Project Costs incurred, and rate mitigation funding received and those built into Hydro's approved test year, along with other supply cost variances. Components of the Long-Term SCVDA are largely aligned with those of the existing SCVDA and are included in the proposed account definition in Schedule 2 to this application.

2.1 Allocation Methodology

Hydro reviewed the definition of the existing SCVDA for changes to be proposed to the deferral account definition for the Long-Term SCVDA, including the methodology for allocating variances to the plan

[3] Per Board Order No. P.U. 1(2025), Hydro will file a methodology for updating the wholesale rate no later than its next GRA or April 15, 2026.

balances for Newfoundland Power and the IIC. As part of this review, Hydro engaged Christensen Associates Energy Consulting, LLC ("Christensen Associates") to review the deferral account practices in other jurisdictions that may provide alternative methods to be considered by Hydro in the long term.

Christensen Associates prepared a report, "Costing and Pricing for Deferral Accounts," which is included as Attachment 1 to this document. The report's findings suggest that Hydro could elect to recover/reimburse costs/credits based solely on energy consumption. This is a simple and well-founded practice in rider pricing for generation-related costs, based on the jurisdictional review. A simple example in the report suggests that a demand and energy cost allocation tied to Hydro's existing cost of service methodology might produce a slightly improved understanding of customer cost responsibility.

Hydro has reviewed the difference between allocating variances from the test year based on an energy-only allocator and allocations that include demand and energy components. In an illustrative example, provided as Attachment 2, assuming a test year with Project Costs and rate mitigation reflected in rates, the allocation of variances of approximately $45.8 million resulted in shifting $0.8 million in costs to Newfoundland Power from IIC using both demand and energy allocators when compared to an energy only allocator. This shift in costs using allocators consistent with those used in the cost of service resulted in an estimated difference in billing impact to Newfoundland Power of a 0.1% increase and Island Industrial customers of a -2.9% decrease.

Hydro recognizes that using the allocators in the cost of service to allocate variances from those costs in the SCVDA would result in a more accurate allocation of costs between customers. Hydro proposes using the allocators approved for the test year cost of service to classify costs and credits as demand or energy related.

Table 1 lists the SCVDA components and the proposed allocators, all of which are consistent with the Cost of Service allocations already approved for use or proposed for approval in this application.

Table 1: Demand and Energy Classification – SCVDA – Long-Term Components

Component	Demand (%)	Energy (%)	Cost of Service Allocation[4]	Approved Board Order No.
Muskrat Falls Project Costs	45	55	System Load Factor	P.U. 37(2019)
Net Revenue from Exports	45	55	System Load Factor	P.U. 37(2019)
Transmission Tariff Revenue	45	55	Proposed	
Rate Mitigation Funding	45	55	Proposed	
Holyrood TGS Fuel	0	100	Energy	P.U. 30(2019)
Utility Load	45	55	Proposed	
Industrial Load	45	55	Proposed	
Greenhouse Gas Credits Revenue	45	55	Proposed	
Other IIS Supply Cost				
Thermal	100	0	Demand	P.U. 37(2019)
Off-Island Purchases	45	55	System Load Factor	P.U. 37(2019)
On-Island Purchases	45	55	System Load Factor	P.U. 37(2019)
Wind	78	22	Demand/Energy	P.U. 37(2019)

To allocate the demand and energy costs to the Island Interconnected customer groups, Hydro is proposing the methodology outlined in Sections 2.1.1 and 2.1.2.

2.1.1 Energy Allocation

Each month, the energy costs will be allocated among the Island Interconnected customer groups of: (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for Utility Firm invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the energy costs which are initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected System customers in the same proportion as the Rural Deficit is allocated in the most recently approved test year Cost of Service Study.

[4] 2019 Test Year System Load Factor was 54.34%; and therefore, 45% demand and 55% energy were used by Hydro in this application for illustrative purposes.

The current month's activity for Newfoundland Power, Island Industrials, and regulated Labrador Interconnected System customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected System customers will be removed from the plan and written off to Hydro's net income (loss).

2.1.2 Demand Allocation

Each month, the demand costs will be allocated among the Island Interconnected System customer groups of: (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from year-to-date kW for Utility Firm invoiced monthly billing demand, Industrial Firm maximum invoiced demand multiplied by the year-to-date months, and Rural Island Interconnected maximum peak demand multiplied by the year-to-date months.

The portion of the demand costs which are initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected System customers in the same proportion as the Rural Deficit is allocated in the most recently approved test year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials, and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the plan and written off to Hydro's net income (loss).

2.2 Cost of Service Methodology

To propose the allocation to customer plan balances for the operation of the Long-Term SCVDA, it is necessary to address the Cost of Service allocation methodology of certain cost/revenue items impacting the Island Interconnected System that have not yet been proposed to or approved by the Board.[5] Those cost/revenue items normally proposed as part of Hydro's next GRA are:

- Rate Mitigation Funding;

[5] Other cost of service issues will be addressed as part of Hydro's next GRA.

- Transmission Tariff Revenue; and
- Greenhouse Gas Credits Revenue.

The cost of service methodology items to be addressed in this application are closely related to the items addressed in the 2018 Cost of Service Methodology Review. In that application, filed on November 15, 2018, Hydro proposed revisions to its Cost of Service Methodology for use in the determination of the test year customer class revenue requirements, reflecting the inclusion of the Project Costs upon full commissioning.

Board Order No. P.U. 37(2019) approved the recommendations in the settlement agreement on the Cost of Service issues agreed to by the parties. The approved recommendations regarding the Muskrat Falls PPA, TFA, and export revenues included:

1) Power purchase costs resulting from the Muskrat Falls PPA and the TFA shall be functionalized as generation;

2) Net export revenues shall be functionalized as generation, which is the same manner as the functionalization of the Project Costs;

3) The classification between demand and energy for the power purchase costs resulting from the Muskrat Falls PPA and the TFA shall be based on the system load factor. For greater clarity, it was agreed that this is inclusive of the costs related to the Muskrat Falls Generation, the LIL, and the Labrador Transmission Assets; and

4) Net export revenues shall be classified using the system load factor, which is the same manner as the classification of the Project Costs.

The 2018 Cost of Service Methodology Review addressed the sharing of net revenue from export sales but did not address the treatment of rate mitigation funds that may be provided from other sources.

The 2018 Cost of Service Methodology Review likened export sales[6] to a form of rate mitigation and proposed that the revenue be classified in the same manner as the classification of the charges from the

[6] "2018 Cost of Service Methodology Review Report," Newfoundland and Labrador Hydro, November 15, 2018, sec. 2.4, p. 6.

TFA and the Muskrat Falls PPA. The proposal on the treatment of export sales was agreed to amongst the parties and approved in Board Order No. P.U. 37(2019).

While the 2018 Cost of Service Methodology Review did not address the treatment of rate mitigation funds from other sources, Hydro believes the same cost of service treatment should apply to other forms of rate mitigation or credits offsetting Project Costs given the purpose of the funding, to reduce the impact of the Project Costs on rates, is consistent.

Hydro proposes the cost of service treatment for the following items that are related to the Muskrat Falls Project.

2.2.1 Rate Mitigation Funding

Rate mitigation funding results from a number of initiatives by the Government to limit the impact of Project Costs on ratepayers, including the financial restructuring of the Lower Churchill Projects, the term sheets signed by the Government, Hydro and the Government of Canada in February 2022,[7] and the Government's Rate Mitigation Plan, which was announced in May 2024.[8]

As part of the financial restructuring, a number of commercial agreements were executed that effectively reduce the charges to Hydro under the MF PPA, including a reduction in the rate of return earned under the Muskrat Falls PPA and the removal of the requirement to pay a debt guarantee fee on Federal Loan Guarantee debt proceeds.

Also as part of the financial restructuring, on December 22, 2022, a commercial agreement between the Government of Canada and the LIL (2021) Limited Partnership was executed, enabling access to $1.0 billion in rate mitigation funding in the form of a convertible debenture. These funds are to be used for rate mitigation and are available in accordance with the terms of the convertible debenture. LIL (2021) Limited Partnership is entitled to make drawings in accordance with the terms and conditions of the convertible debenture and then transfers this funding to Hydro for the purpose of rate mitigation, to offset Project Costs owed from customers. To date, approximately $295 million has been transferred to

[7] "Financial Restructuring Agreement for the Third Federal Loan Guarantee and LIL Investment Finalized," Newfoundland and Labrador Hydro, March 31, 2022. https://nlhydro.com/financial-restructuring-agreement-for-third-federal-loan-guarantee-and-lil-investment-finalized/

[8] "Provincial Government Announces Finalization of Rate Mitigation Plan", Government of Newfoundland and Labrador, May 16, 2024. https://www.gov.nl.ca/releases/2024/iet/0516n01/.

Hydro from LIL (2021) Limited Partnership and used to pay down the balance owing from customers in the existing SCVDA. This funding will continue on an annual basis until the convertible debenture is fully drawn.

The rate mitigation plan announced by the Government on May 16, 2024, included direction on rates for customers on the Island Interconnected System and also funding for balances in the SCVDA. The rate mitigation plan, as directed in Order in Council OC2024-062, requires that any additional funding required to reduce the balance in the SCVDA and achieve the 2.25% targeted increase come from Hydro's own resources. Orders in Council OC2024-062 and OC2024-063 directed the Board of Directors of Nalcor and Hydro[9] that any additional funding required to mitigate Lower Churchill Project Costs or to retire the 2023 SCVDA balances of $271 million be through Nalcor Energy's and Hydro's own sources.

Rate mitigation initiatives described above have resulted in reductions in amounts charged to Hydro through the power purchase agreements, as well as providing sources of rate mitigation funding to be used by Hydro to offset the rate impacts of Project Costs.

Given that the purpose of rate mitigation is to offset the rate impacts of Project Costs, and that Project Costs are functionalized as generation and allocated in the Cost of Service Methodology using Hydro's system load factor, for the purpose of cost of service functionalization and classification Hydro proposes:

- Rate mitigation funding be functionalized as generation; and
- The classification between demand and energy for rate mitigation funding shall be based on the system load factor.

2.2.2 Transmission Tariff Revenue

The export of energy through the Newfoundland and Labrador Transmission System involves the payment of a "point-to-point" transmission tariff by the transmission customer that requires the transportation of the export energy. The payment of the published transmission tariff to the Newfoundland and Labrador System Operator provides additional revenues to Hydro to partially offset

[9] In December 2024, the Hydro Corporation Act, 2007, was repealed and replaced by the Hydro Corporation Act, 2024, which served to finalize the legal merger of Nalcor Energy into Hydro ("Amalgamation"). As a result of the Amalgamation, Nalcor's and Hydro's assets, liabilities, obligations and agreements continue under the new Hydro, and all Nalcor subsidiaries are now Hydro subsidiaries. These subsidiaries will continue to operate as they did prior to Amalgamation.

Project Costs. The amount of additional revenues will be dependent upon the transmission bookings each year.

Transmission Tariff Revenue, similar to Net Revenue from Exports, is revenue that Hydro is proposing to be credited to partially offset Project Costs. This revenue, like Net Revenue from Exports, is available to Hydro only as a result of the Muskrat Falls Project and the resulting Interconnection to the North American grid.

Hydro recommends that Transmission Tariff Revenue be treated the same as Net Revenue from Exports for cost of service functionalization and classification. Hydro proposes:

- Transmission tariff revenue be functionalized as generation; and
- The classification between demand and energy for transmission tariff revenue shall be based on the system load factor.

2.2.3 Greenhouse Gas Credits

The Government's *Management of Greenhouse Gases Act* came into effect on January 1, 2019. This legislation provides for Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions. Under the *Management of Greenhouse Gases Act*, Hydro may sell these performance credits to certain other facilities in the province, of which there are 14, excluding the Holyrood TGS.

Hydro has two regulated facilities under the *Management of Greenhouse Gases Act*: the Holyrood TGS and the Holyrood Combustion Turbine ("CT"). For the Holyrood TGS, baseline production was set at the isolated island level projected by Hydro in the 2012 study that informed the development of Muskrat Falls, therefore providing the facility the opportunity to earn performance credits for over-achieving its greenhouse gas reduction target in a year. The Holyrood CT was assumed to have minimal operation and is required to meet on-site greenhouse gas reduction targets through reduced generation.

Since the performance credits are based on the difference between generation in a year as if the Holyrood TGS had continued to operate in the absence of the Muskrat Falls Project (as projected in 2012) and actual generation in that year, Hydro recommends consistent Cost of Service functionalization and classification of the revenue from the sale of these credits as the Cost of Service functionalization and classification of Project Costs. Hydro proposes:

- Greenhouse gas credit revenue be functionalized as generation; and
- The classification between demand and energy for greenhouse gas credit revenue shall be based on the system load factor.

2.3 Other Allocation Issues

2.3.1 Load Variation

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

The load variation is calculated using the marginal cost of energy[10] for Newfoundland Power and the average embedded cost of energy (4.428 cents per kWh) for Island Industrial customers based on the 2019 Test Year. As load changes, customer revenue is impacted, but the export value in the deferral account also changes since it is the marginal cost of supply in the Island Interconnected System. As more energy is sold to Island Interconnected customers compared to the test year, less energy is available to export. The opposite is also true: as customer load or sales decline, more energy is available to export. These variations in export sales are reflected in the Net Revenue from Exports component of the SCVDA.

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

[10] Based on the test year No. 6 fuel cost at the Holyrood TGS of 18.165 cents per kWh in the 2019 Test Year. In Board Order No. P.U. 1(2025), the Board approved a revised wholesale rate to be charged to Newfoundland Power reflecting the market value of exports as the marginal cost. The second block energy rate effective January 1, 2025, includes a seasonal rate of 9.698 cents per kWh for winter months of December to March and 3.354 cents per kWh for the non-winter months of April to November.

2.4 Finance Charges

During the proceeding related to Hydro's application establishing the existing SCVDA, parties raised concerns in relation to the proposed calculation of finance charges on the SCVDA. In its application, Hydro had proposed to calculate financing charges using approved Weighted Average Cost of Capital ("WACC") given the proposed blending of historical balances from existing deferral accounts with the payments under the Muskrat Falls PPA. The IIC Group submitted that interest should be accrued at prevailing short-term borrowing costs and noted that, in the near term, the account will primarily operate with negative balances, the balances are expected to be material and fast-growing, and the payments will be made using short-term debt financing. Newfoundland Power also opposed the use of Hydro's WACC and submitted that short-term financing costs be used until the long-term approach is determined through Hydro's next GRA.

In Board Order No. P.U. 33(2021), the Board ordered the calculation of finance charges on the existing SCVDA to be calculated based on Hydro's short-term borrowing costs. The Board also stated that the Hydraulic Production Variation component and the Current Plan balances of the Rate Stabilization Plan ("RSP") can continue to be calculated using Hydro's approved WACC, and the three existing supply accounts should continue without monthly interest charges as they are included in the 2019 Test Year Rate Base. The Board noted Hydro's plan to use short-term borrowing in the near term and concluded it was appropriate to use short-term borrowing costs as the basis of the calculation of financing charges on the existing SCVDA.

Since the establishment of the existing SCVDA, Hydro has implemented a Project Cost Recovery Rider[11] to recover some of the costs in the account from customers, and rate mitigation funding has been applied or is committed to reduce the balance in the account to zero, in accordance with the Government's rate mitigation plan. Therefore, the existing SCVDA is currently operating in a similar manner to the long-term approach for any deferral account relating to supply costs, such as the RSP, where cost variances are collected annually. In the case of the existing SCVDA, collections of balances come from two sources: customers and rate mitigation funding.

[11] A Project Cost Recovery Rider was implemented for Newfoundland Power on July 1, 2022 and for Island Industrial Customers on January 1, 2024.

The proposals in this application are for the long-term operation of the SCVDA to come into effect after the next GRA. This account will continue to capture variances between Hydro's incurred supply costs and those included in Hydro's most recently approved test year; however, these variances and the resulting balance in this account are expected to be much lower in comparison to those in the existing SCVDA as Project Costs and rate mitigation funding will be included in Hydro's Cost of Service and test year revenues in its next GRA, prior to this account becoming effective. Contrary to the existing SCVDA, when it was originally created, balances are not expected to be material and fast-growing, and this account will operate in a similar manner to Hydro's historical deferral accounts relating to supply costs, such as the RSP, where balances in the account are collected annually. For these reasons, this long-term approach to the SCVDA differs from the existing SCVDA at the time it was established; Hydro is proposing that the interest on the Long-Term SCVDA be calculated according to current regulatory practice in Newfoundland and Labrador, using the WACC as approved in Hydro's test year. The calculation of Finance Charges based on Hydro's approved WACC has been included in the proposed account definition.

2.5 Accounting Deviation

As a result of the amalgamation, under IFRS, a change to the accounting for rate mitigation funding is required. Pre-Amalgamation, rate mitigation funding was transferred from Nalcor, where it was recorded as an expense, to Hydro, where it was recorded as revenue and then deferred as part of the SCVDA, reducing the balance owing from customers.

Post-Amalgamation, the recording of rate mitigation funding as revenue is not permitted under IFRS, as there is no transfer of funds from one legal entity to another. Effective January 1, 2025, in accordance with IFRS, rate mitigation funding will be recorded as an expense within the non-regulated operating segment of Hydro with a credit directly to the SCVDA to reduce the balance owing from customers. As a result, Hydro would not record the revenue relating to the rate mitigation funding.

In Hydro's next test year, Project Costs and rate mitigation funding will be reflected in customers' base rates, targeting increases of 2.25% per the Government's rate mitigation plan. When rate mitigation is reflected in customer base rates, the recognition of the funding as revenue is required to properly reflect Hydro's regulated net income. If rate mitigation funding included in customer base rates is not recognized as revenue, Hydro's regulated earnings will not include the rate mitigation contribution in the results of operations, likely resulting in a net loss.[12]

Hydro is proposing an accounting deviation, effective January 1, 2025, to continue with consistent accounting practice prior to amalgamation of recording rate mitigation funding as revenue in the regulated operating segment. For external financial reporting purposes, the rate mitigation revenue would be recorded as a regulatory adjustment under IFRS 14 — *Regulatory Deferral Accounts*.[13]

The requested accounting deviation will have no impact on customers.

3.0 Summary

The SCVDA was approved to enable the deferral of costs related to the Muskrat Falls project prior to their recovery. This existing deferral account will continue to accumulate costs, revenues and variances from the 2019 Test Year until approval of Hydro's next GRA; after which, Hydro will transition to the long-term SCVDA.

The proposals described herein for the long-term SCVDA definition include the allocation methodology for transferring monthly variances to the plan balances for Newfoundland Power and Island Industrial Customers, as well as the finance charges to be applied to the account for the long-term. The approach for the disposition of account balances will be addressed in a future application to the Board.

As part of defining the Long-Term SCVDA operation, Hydro is proposing to update the Cost of Service Methodology for the consistent treatment of rate mitigation funding, transmission tariff revenue, and greenhouse gas credits revenue.

Hydro's proposed accounting deviation for rate mitigation funding will facilitate the consistent financial reporting of rate mitigation funding pre- and post-amalgamation and the incorporation of rate mitigation funding into Hydro's test year cost of service in its next GRA.

[12] Muskrat Falls Project Costs will be included as an expense, with only the variance from the test year deferred in the Long-Term SCVDA. If rate mitigation is not recorded as revenue consistent with the expense, Hydro will recognize a loss.
[13] In addition, the variance from the actual rate mitigation and the test year rate mitigation will be recorded in the SCVDA, with a regulatory adjustment recorded on the income statement.

Approval of Hydro's proposals will further define the operation of the Long-Term SCVDA as well as address the related Cost of Service Methodology issues prior to Hydro's next GRA.

Attachment 1

Costing and Pricing for Deferral Accounts

Christensen Associates

Costing and Pricing for Deferral Accounts

for
Newfoundland and Labrador Hydro

by

Bruce Chapman

With the assistance of
Michael Vigdor

April 16, 2025

800 University Bay Dr #400
Madison, WI 53705-2299

608.231.2266
www.CAEnergy.com

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Costing and Pricing for Deferral Accounts

for

Newfoundland and Labrador Hydro

by

Christensen Associates Energy Consulting, LLC

April 16, 2025

1. INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) initiated the Supply Cost Variance Deferral (SCVD) account to manage cost under- and over-recovery associated with the Muskrat Falls project. That project's contractual terms require that its customers begin paying for the project upon initiation of service. Beginning in November 2021, Hydro began using the SCVD account to compute customer responsibility to match billings to costs. At then-current rates, the account quickly began to accumulate under-recovered costs. The issue arose as to what each rate class's responsibility for those costs should be.

This report reviews Hydro's options for costing and pricing of the amounts in the SCVD account, bearing in mind their potential variability and the limitations on revenue imposed by the rate mitigation arrangement agreed with the province. The report first sets out the issues involved and describes the components of the SCVD account and then presents the alternatives for costing and pricing that comport with cost allocation and rate design theory. The next section documents research on how deferred costs are handled within the North American utility industry at present. A section illustrating the significance in billings of alternative approaches to the problem follows. The report concludes with recommendations regarding costing and pricing of SCVD amounts.

2. ISSUES AND PRICING ALTERNATIVES

Cost Recovery Outside Rates

Deferral accounting is a standard component of utility costing methods. Because the timing of payments for goods or services cannot always coincide with their actual delivery, the matching principle requires that utilities shift the timing of cost recovery and disbursement to match the timing of services rendered.

A related problem for utilities is that their pricing is determined in periodic, infrequent rate applications. Under-recovery of revenues that triggers a rate application offers delayed relief.

When expenses are large, variable, and beyond the control of the utility, the convention of using riders to adjust pricing and revenue recovery at regular intervals between rate applications has developed. The leading example of such an approach is a fuel cost recovery rider, whose price for fuel and purchased power can be changed at regular intervals to counteract over- and under-recovery of costs. More generally, riders have come to serve a wide variety of cost recovery purposes, including recovery of fixed costs for a period of time where the costs are deemed not to belong in revenue requirements. (An example of such a cost is nuclear decommissioning costs. The plant is no longer used and useful and yet cost recovery must continue while decommissioning occurs.)

Issues of both timing matching and cost variability can be found with Hydro's new SCVD account. Muskrat Falls costs are largely fixed and have already been incurred, but cost recovery ought, by normal costing practice, to be recovered based on customer usage and peak demand levels. Since these can be forecasted but not observed until after the fact, and since costs in revenue requirements supporting rates are based on forecasts, there will develop discrepancies between cost recovery and cost obligation. These discrepancies can be both variable around a forecasted level or path and can depart systematically from the path if actual usage is systematically greater or less than forecasted.

Components of the SCVD Account

Hydro's SCVD account consists of several components, some pertaining directly to the Muskrat Falls project and its associated transmission investments, with the rest pertaining to other generation-related costs and revenues. Some components are cost-related while others are revenue-related. Cost increases are recorded as positive while revenue increases are recorded as negative; that is, a positive number across all components is an underage to be recovered while a negative is an overage to be reimbursed.

Table 1 provides a summary of the account's components, organized in the manner presented by Hydro in its computations. Cost-related calculations are based on the difference between actual and baseline costs, with the result that costs above those included in rates are identified as positive amounts owed by customers to the utility. Revenue-related calculations are based on the difference between baseline and actual revenues, with the result that higher than expected revenues yield a negative amount owed by the utility to the customers. The total across all components is just the net owed by customers to the utility. (The component numbers in the leftmost column are as identified in Hydro's SCVD account definition document.[1]) Also, while the SCVD account includes in its listing project cost recovery from the utility and industrial classes, these costs are recovered via a separate rider, the Project Cost Recovery rider, and are listed as reductions in customer obligations in the deferral account.

The focus of the deferral components is generation costs, including the transmission costs that can be viewed as generation-related since the Labrador-Island Link has the sole function of

[1] Newfoundland and Labrador Hydro, *Supply Cost Variance Deferral Account Definition*, Schedule A, Order No. P.U. 4 (2022), Effective Nov. 1, 2021. One component, no. 9, Rural Rate Alteration, does not appear in the table, presumably not having appeared the calculations so far. This component is revenue-related: rate increases reduce need to recover revenue. This component applies to the Utility customer only.

delivering Muskrat Falls power to the Island grid. The issue is how to structure the SCVD account's pricing to recover costs (and credit overages).

Table 1
SCVD Account Component Characterization

No.	Component	Cost-Related	Revenue-Related
1	Muskrat Falls Deferral Cost Variance	x	
6	Net Revenue from Exports Variance		x
7	Transmission Tariff Revenue Variance		x
	Muskrat Falls Project Costs	sum of above	
2	Rate Mitigation Fund		x
4	Holyrood Fuel Cost Variance	x	
3	Project Cost Recovery		
	Utility Customer		x
	Industrial Customers		x
5	Other IIS Supply Cost Variance	x	
8	Load Variance		
	Utility Customer		x
	Industrial Customers		x
10	Greenhouse Gas Credit Variance		x
	Total	sum of above	

The "Other IIS Supply Cost Variance" component contains several subcomponents: thermal and wind costs, plus off-island and on-island purchases.

Costing and Pricing Alternatives

Traditional methods of cost recovery for departures of actual costs from the costs incorporated in revenue requirements and rates usually involve simple usage charges applicable to all customer loads. Computationally, the utility simply observes the difference between actual and forecasted cost recovery and divides this difference, positive or negative, by actual historical or forecasted total consumption to get a per-kWh price applicable to all customers. This price is adjusted by the overage or underage from the previous pricing period, again divided by the usage total. Under this scheme the utility posts a single per-kWh rider price applicable to all customers. Over time, the price oscillates around the expected level.

One problem with this approach is that an energy-only cost allocation and charging mechanism will usually be at variance with the generation costing methods of the cost-of-service (COS) study that underpins rates. Generation cost classification within COS studies has traditionally offered utilities a broad range of alternatives. An early approach was to classify generation rate base and generation non-fuel expenses as 100% demand-related, and then allocate costs to class via a conventional demand allocator, typically a version of coincident peak (CP).

Over time, demand- and energy-related methods became common, to allow for the distinction between peak-related and base-load generation facilities, with the former being deemed demand-related and the latter energy-related. Demand-related costs were then allocated to class using a CP allocator and energy-related costs were allocated based on total annual usage. The NARUC COS Manual documents this range of methodology alternatives in detail.[2]

Fuel costs and power purchases were usually deemed exclusively energy-related. Some utilities would include forecasted fuel consumption in rates and then provide a fuel adjustment charge/credit rider for departures from forecast due consumption or fuel price variation. Others would exclude all fuel and power purchases from rates and apply a fuel cost recovery rider to recover full costs. Regardless of the method, energy-only pricing was the norm.

The increasing importance of power purchases, and the use of both demand and energy pricing in purchase contracts, has caused utilities to reconsider how to treat this rider item. Since some power purchases have a capacity-related component, a share of demand-related costs has come to be collected via a per-kWh price. If various rate classes have differences in peak coincidence or load factor, then implicit cost shifting can occur with respect to the demand-related component of fuel cost recovery. One issue is whether the cost shift is significant enough to make price differentiation across customers within the fuel rider worth the increase in rate complexity.

A remedy for this costing problem is to apply the cost classification and allocation principles of revenue requirements to fuel and purchased power. The result is separate class-based calculation of revenue recovery and separate pricing. The pricing can be energy-only or involve demand-and-energy pricing. The former is comparable to past practice but the prices are now class-specific. The latter approach requires metering and data management capability, and would apply only in cases where customers are demand metered, leaving customers with energy-only rates on an energy-only rider.

Class-specific energy-only pricing resolves issues of cost shifting between classes. Classes that are more peak coincident will be revealed to have a higher cost to serve with respect to rider costs, and will have a higher (or a less negative) energy price than other customer classes. Demand-and-energy pricing will not only resolve interclass cross subsidy, but it will also improve the match of customer bills with cost to serve within class. High load factor customers will not cross-subsidize low load factor customers under conditions of cost recovery. Again, whether this benefit is worth the extra complication is an issue.

3. JURISDICTIONAL REVIEW

If Hydro is to consider modifications to its cost allocation and pricing of deferred amounts, it would be helpful to know about experience elsewhere. This project investigated deferral account practices primarily in Canada, and found helpful examples in the US as well. Most electric utilities have riders whose purpose is to collect revenues or provide credits associated with revenues and costs not found in the COS study and recovered in standard rates.

All riders are, at least indirectly, mechanisms for engaging in deferral accounting, since they change the timing and incidence of costs and revenues. The most common rider, a fuel adjustment charge, corrects the original recovery of fuel costs based on forecasted fuel prices by

[2] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, Chapter 4.

imposing a fuel charge or credit per kWh on all customers, typically with a one-quarter to one-year lag. Similarly, a fuel cost recovery rider uses similar lags to recover fuel and purchased power costs with some degree of lag. Other riders, which serve a wide variety of purposes, recover costs or provide credits according to a fixed cost allocation and timing pattern, as approved by the regulator. Often the deferral of collection or payment is not a primary consideration but instead an incidental outcome of the calculation of the price once actual, as opposed to forecast, information is known.

Hydro's circumstances in the case of the SCVD account are similar: the objective is to charge or credit customers based on the difference between actual and forecast costs or revenues. Thus, experiences elsewhere with riders and deferral accounts are likely to be germane to Hydro's issue of how to allocate costs and revenues and charge/credit customers to achieve accurate billing.

Canadian Practices

Table 2 presents a summary of the use of deferral accounting in Canada, covering the main electric utilities in each province, from west to east. The table reveals that deferral provisions are common across the country, but not universal. Most use a simple energy charge as the basis for cost recovery/crediting of excesses.

The exception is BC Hydro, which uses a percentage-of-bill approach to scale up/down bills, excluding taxes and fees. The utility has two riders, the Deferral Account Rate rider and the Trade Income Rate rider, which are of this form. The latter covers net revenues from its wholesale trades while the former covers all other adjustment items. The Deferral Account Rate rider captures deferrals from about thirty separate accounts. These expenditures cover everything from storm cost recovery to grid enhancement costs. In both cases, the percentage methodology is supported by a costing approach that permits allocation to class on the basis of customer, demand, and energy allocators. However, this does not appear to apply, since the outcome in this case is a uniform percentage across all classes.

Fortis BC and Fortis Alberta use the conventional energy-only approach to rider pricing. Other Alberta utilities do not make use of a rider but adjust revenue recovery by modifying base revenue requirements. SaskPower currently makes no provision for deferred costs.

Manitoba Hydro identifies deferral accounts by type and petitions the regulator to determine which costs can be incorporated into the rate base, either directly or amortized over time, and which costs can be recovered as riders. Examples of deferral accounts include Demand Side Management expenditures, regulatory costs, site restoration expenditures, deferred taxes and the Purchase Gas Variance Account. Currently Manitoba Hydro has no riders to recover deferred costs.

Table 2
Deferral Accounting Examples at Canadian Electric Utilities

Province	Utility	Tracks Deferred Expenses and Recuperates Costs	Adds Deferred Costs to Rate Base	Separate Rider for deferred cost expenditures	Rider Payment
British Columbia	BC Hydro	Y	Y	Y	% of Total Bill
	Fortis BC	Y	Y	Y	Energy Charge
Alberta	ATCO	Y	Y	N	
	Fortis Alberta	Y	N	Y	Energy Charge
	EPCOR	Y	Y	N	
Saskatchewan	SaskPower	N	N	N	
Manitoba	Manitoba Hydro	Y	Y	Y	Energy Charge (Currently no riders active)
Ontario	Alectra	Y	Y	Y	Energy Charge
	London Hydro	Y	Y	Y	Energy Charge
	Toronto Hydro	Y	Y	Y	Energy Charge
	Hydro One	Y	Y	N	
Quebec	Hydro Quebec	N	N	N	
New Brunswick	NB Power	Y	Y	Y	Energy Charge
Prince Edward Island	Maritime Electric	Y	Y	N	
Nova Scotia	Nova Scotia Power	N	N	N	
Newfoundland and Labrador	NL Hydro (RSP-hist)	Y	N	Y	Energy Charge
	Newfoundland Power	Y	N	N	

The Ontario Energy Board (OEB) is responsible for prescribing accounting procedures/requirements for deferral or variance accounts. Utilities are required to keep a uniform system of accounts which includes at least seven different types of deferral accounts as well as other variance accounts. They are as follows:

- Renewable Connection Capital Deferral Account
- Renewable Connection OM&A Deferral Account
- Renewable Generation Connection Funding Adder Deferral Account
- Smart Grid Capital Deferral Account
- Smart Grid OM&A Deferral Account
- Smart Grid Funding Adder Deferral Account
- Deferred Losses from Disposition of Utility Plant

The OEB reviews these account balances and prescribes methodology for recovering these costs. These accounts are either incorporated into the rate base or utilities can be granted permission to add a rider that recovers costs. Currently London Hydro, Alectra and Toronto Hydro have been granted permission to have riders for the “Disposition of Deferral/Variance Accounts” as well as riders for the “Disposition of Capacity-Based Recovery”. These riders recover most of the expenses tracked in the above-listed deferral accounts. The riders are applied as per-kWh energy charges to customer accounts. Typically, charges vary by customer class.

Hydro One in Ontario does not have any direct riders for deferral recovery. Instead, they track deferral accounts and then add the account totals to the rate base to be amortized over an extended period, with duration depending on circumstance, usually not more than 60 months.

Hydro-Quebec used deferral accounts until 2019, but no longer does so. The utility can petition the Regie de l'energie for recovery of unexpected additional costs, but these costs do not flow through deferral accounts. The utility's view, as expressed in an annual report, is that the absence of these account computations and means of balancing excesses and shortfalls in revenue exposes the utility to the risks of random variation in usage and costs.[3]

New Brunswick Power calculates an Energy Supply Cost Variance associated with each fiscal year covering the difference between actual and forecasted energy supply cost. The costs include fuel expenses, purchasing and transportation expenses, renewable energy credits, commodity hedges, water and land rights, and profits from fuel sales. NB Power also calculates the Electricity Sales and Margin Variance account, which is the difference in actual and forecasted sales revenues. The two accounts are totaled, and NB Power then proposes a time period over which they plan to recover or reimburse the balance of the two above listed accounts along with a set of riders that achieve that recovery. If they recover the expenditures through a rider it is applied as a per-kWh energy charge that varies by rate class. This structure is similar to the two components of Hydro's SCVD account's Muskrat Falls project deferral computations, which compute quantity- and cost-related variation.

Maritime Electric's Energy Cost Adjustment Mechanism (ECAM) operates in a manner similar to that of other fuel and purchased power riders. The ECAM mechanism is interesting in that it allows explicitly for the deferral of "uncontrollable changes in energy related costs", which suggests a greater degree of discretion than conventional mechanisms that have fixed formulations for computing rider prices. This discretionary element apparently was used in December 2020 to postpone bill increases during the covid pandemic.[4]

Nova Scotia Power, like SaskPower, does not make provision for deferral-related pricing.

In Newfoundland and Labrador, Hydro retains, by regulatory requirement, its Rate Stabilization Plan (RSP) for recovery of historical costs. That provision is a standard energy-only mechanism, but the two main classes of Island customers, the utility and industrial customers each have their own price, based on energy-based allocation of costs.[5] The RSP also explicitly considers financing charges, an element not discussed, or perhaps implicit, in other utilities' riders.[6]

Newfoundland Power does not make provision for deferral pricing other than to pass through the riders from NL Hydro that are adjuncts to the Utility rate that NL Hydro charges Newfoundland Power. The energy prices of all rates are adjusted to reflect annual changes in the Rate Stabilization Account.

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[3] Hydro-Quebec, *Annual Report, 2023*, p. 30.

[4] Maritime Electric, *Application and Evidence of Maritime Electric Company, Limited*, December 17, 2021, pp. 9-10.

[5] Newfoundland and Labrador Hydro, *Schedule of Rates, Rules, and Regulations*, Updated January 1, 2025. See sheets RSP 1-3.

[6] Additionally, the RSP includes minor Newfoundland Power cost transfers, but these are excluded from illustrative calculations below.

Canadian utilities, perhaps because many of them have been historically excused from the need to engage in fuel purchases for a large percentage of generation, do not all have deferral provisions in their tariffs or in their costing. However, those that do offer useful examples in that some differentiate pricing by rate class rather than simply using a single price, or percentage adjustment, for all classes. Maritime Electric provides one instance of discretion in the timing of deferral, albeit in the context of an extreme event, the covid pandemic. The review did not uncover an example of a utility offering an example of pricing other than energy-only (per-kWh) pricing.

Examples from the United States

The United States has a wider array of utility practices than Canada due to a combination of geographic and regulatory differences between the two countries. Due to these differences, there tends to be a greater diversity in rate and rider design in the United States. With respect to deferral accounting, some utilities choose to treat deferral accounts in the same manner as Hydro One in Ontario. They track deferred expenses and add them to the rate base, usually to be amortized over an extended period with approval from regulators. It is relatively rare to see specific riders that address deferral accounting. However, there are many utilities that utilize riders to recover specific costs in interesting or applicable ways.

We examined a selection of U.S. electricity providers with unique or relevant rate riders that could help NL Hydro with their deferral accounting practices. Below are some of the highlights of the search.

Florida Power and Light (FPL). FPL, like many large U.S. utilities, has a variety of rate riders that help track costs for expense accounts and programs. Despite the numerous different types of riders, they do not have any that are specifically designed to recover deferred expenses. However, FPL does have two rate riders that have designs that are structurally relevant or of interesting design.

The first is their Transformation Rider. This rider is designed to recover the costs for customers who need voltage transformation, typically from primary distribution (at least 2400 volts). Instead of an energy charge in $ or ¢/kWh customers can either choose to have the company provide transformation or supply their own and receive a $0.36 credit per kW of billing demand.

FPL also has a solar power facilities rider for the purpose of recovering costs associated with the installation and maintenance of solar facilities for non-residential customers who elect to have FPL install and maintain said facilities. Customers pay a Monthly Service Payment on top of their standard bill which covers capital costs and expenses (which can include operations and maintenance, administrative, depreciation, taxes, etc.) both of which are levelized over the terms of the contract.

Oklahoma Gas and Electric (OG&E). OG&E has a variety of riders with prices differentiated by voltage service level. A particularly relevant design for Hydro's purposes is the Grid Enhancement Mechanism, which recovers the annual expenditures on capital for the purpose of grid enhancement. This rider is applied in the form of an energy charge for energy-only rates and as a demand charge for energy and demand rates.

AES Ohio. AES Ohio does not have a deferral rider. In order to recover deferred expenses, they directly request of the regulator that the necessary amount be added to the rate base and add a per-customer fixed charge on their expenses. This has proved controversial in recent rate cases in Ohio.

AES Ohio has one rider of possible relevance to Hydro: their Distribution Investment Rider. The rider is designed to recover any incremental investments in distribution-related capital. Unlike most other riders at AES Ohio the costs are recovered through a percentage added to the base distribution charges to each monthly customer bill.

DTE Energy. This utility is distinguished by its relatively numerous riders. Of interest to Hydro is the fact that three of these have demand-based charges. These serve standby, interruptible, and capacity release customers. Riders of this sort are often treated as rates at other utilities, but they serve as an example of the extension of COS allocation practices and principles into the realm of riders.[7]

Salt River Project (SRP). SRP is a community-owned electric utility in Arizona that recently introduced demand-based costing into its fuel cost recovery. A component of their base rates is the "Fuel and Purchased Power Adjustment Mechanism" (FPPAM) with the price expressed as a unit of energy only, including for rates where demand is a price component. SRP's rates are time differentiated: most customers face three seasons and up to three price periods per season. The FPPAM prices are differentiated in the same manner: seasonal TOU (where that design applies to the other components of the rate). FPPAM prices change periodically between rate cases, so the mechanism acts in the same manner as a rider at other utilities.

The FPPAM is somewhat unconventional in that it acts as a rider, adjusting price level periodically to reflect changes in fuel and purchased power costs, but is embedded in rates. This fact does not diminish its usefulness as an example, though, of new cost classification methodology.

The feature of interest for NL Hydro is that the COS study that underpins these rates classifies purchased power as partly demand-related, with the demand component being based on the utility's demand-based payments for power. This is a new feature of SRP's COS study, and the related rates go into force in November 2025.

The FPPAM component of SRP's rates is possibly of more than passing interest to Hydro. Normally the FPPAM operates in the manner of a fuel cost recovery rider, with its price moving up and down over time to keep fuel and purchased power cost balances within a predefined range around a target level of zero. In this particular case, the FPPAM provision of rates acted as a rate mitigation fund during the covid pandemic. The utility's Board of Directors elected to forgo deferred fund recovery on two occasions.[8]

This example offers Hydro a precedent for flexibility in the design and operation of its deferral accounting in that a similar principle of flexibility in cost classification can be permitted, and then expressed in class-specific pricing of a rider-based charge. Furthermore, it is not a great leap to

[7] See the GRA Workshop presentation for NL Hydro, entitled *Costing and Pricing to Support a General Rate Application*, Dec. 11, 2023.
[8] Source: presentation to the Board by B.G. Shoemaker, 8/22/24.

consider recovering demand-related costs via a demand-related charge for customer classes where demand metering already occurs.

In summary, US utilities widely use riders to recover/credit both fuel and purchased power costs/overages and a wide variety of other costs as well, although cost deferral is not usually a significant element of the design. However, examples of demand-based cost allocation within riders are beginning to emerge, providing some precedents to Hydro should the utility contemplate such a strategy for the SCVD account.

4. IMPLICATIONS OF ALTERNATIVE APPROACHES

Theory and practice elsewhere appear to allow Hydro a variety of costing and pricing alternatives. One practical consideration in deciding how to proceed might be the expected scale of the flows. Is the dollar value sufficient that adopting more complex methods can be justified?

The SCVD account's history is brief, since the account has been active only since November 2021, when Muskrat Falls and the LIL were placed in service. Early months were characterized by large dollar flows in the months leading up to the first general rate application since the account began operating. Account balances in late 2022, the first full year of operation, were on the order of $190 million.

The account balance, following general rate application review and approval, is planned to vary around a value of zero. Naturally, variations in consumption and export pricing will produce oscillation around this value. Additionally, the potential variability in timing (but not the amount) of Rate Mitigation Fund payments could produce large balances. Note, however, that the plan to modify the price applicable to customers is for annual updates. Additionally, this update will, reportedly, take account not only of actual Fund receipts but also expected receipts. (To do otherwise would produce a large SCVD account balance and high price, only to bring a large reversal in the following year due to previous overcharging.)

As a result, substantial balances may arise of part-year duration due to the smoothing effect of pricing in an environment of potentially quite variable supply costs arising from underlying variability in consumption levels and export prices. One way to evaluate the alternatives in costing and pricing is to consider the likely cost shifts between these alternatives for historical sizeable levels of the account, under the assumption that these are likely to be larger than expected future levels.

Consider an example in which the variance in cost is that of 2024, about $36.75 million in increased cost. The components of that cost variance appear in Table 3. The Muskrat Falls cost variance is about $659 million, visible in the rightmost column. The Rate Mitigation Fund transfer of about $421 million partially offsets the cost variance. Other variances produce the net result in the bottom right-hand corner.

Table 3
Variances in SCVD Account Components – 2024 Budget
(Thousands of Dollars)

No.	Component	Cost-Related	Revenue-Related	Total
1	Muskrat Falls Deferral Cost Variance	716,647		
6	Net Revenue from Exports Variance		(39,114)	
7	Transmission Tariff Revenue Variance		(18,206)	
	Muskrat Falls Project Costs			659,326
2	Rate Mitigation Fund		(421,000)	
4	Holyrood Fuel Cost Variance	(127,372)		
5	Other IIS Supply Cost Variance	(7,766)		
3	Project Cost Recovery			
	Utility Customer		(56,126)	
	Industrial Customers		(7,762)	
8	Load Variance			
	Utility Customer		(4,438)	
	Industrial Customers		3,488	
10	Greenhouse Gas Credit Variance		(1,600)	
	Total			36,751

Recovery of this amount adds about 4.9% to total billings, based on an estimate of 2025 billing quantities and rates.[9] (The bill total includes both base revenue and RSP, PCR, and CDM revenues applied to forecasted quantities.) A simple energy-only allocation of cost under the above assumptions adds 5.6% to the Utility customer's bills and about 1.7% to the Island Industrial customers' bills. The Island Rural customers' bills would increase by about 0.4%, after allowing for the reallocation of most of their bill impact to the Utility customer. The residual appearing in the table is reallocated to Labrador Interconnected customers and written off to net income.[10] The actual bill impact for the Island Rural customers is thus zero.

An alternative to this approach involves allocating costs according to Hydro's existing cost allocation rules. For this example, the demand and energy shares are based partly on Hydro's COS rules and partly on conjecture as to what the demand shares of the other accounts might be, depending on the costs incurred. Table 4 presents these assumptions.

The bases for these assumptions are that: 1) shares for Muskrat Falls costs and export revenues are based on system load factor (e.g. if the system load factor is 55%, then the energy share is 55%); 2) the rate mitigation fund should be classified in the same manner as Muskrat Falls; 3) Holyrood fuel costs variances are entirely energy-related; 4) other IIS cost share variations

[9] Changes in billing quantities and rates to 2025 permit reflection of current conditions in the example calculations. Average SCVD Account balances are not forecasted for this year.

[10] Variances allocated to Island Rural customers is re-allocated between Utility and Labrador Interconnected customers in the same proportion that the Rural Deficit was allocated in the approved 2019 Cost of Service Study, which is 96.1% and 3.9%, respectively. The Labrador Interconnected amount is then written off to net income. In the absence of reallocation, the Utility customer bills would increase by 4.6% and the Island Rural bills would increase by 9.7%.

are based on an average of historical and forecast shares provided by Hydro;[11] and 5) load variances are associated with typical generation changes, and should be classified on the basis of system load factor; and 6) greenhouse gas variances are associated with Muskrat Falls production, and should be classified in the same manner as Muskrat Falls itself, i.e. system load factor.

Table 4
Assumed Demand and Energy Classification of SCVD Account Components

No.	Component	Demand	Energy
1	Muskrat Falls Deferral Cost Variance	45%	55%
6	Net Revenue from Exports Variance	45%	55%
7	Transmission Tariff Revenue Variance	45%	55%
	Muskrat Falls Project Costs		
2	Rate Mitigation Fund	45%	55%
4	Holyrood Fuel Cost Variance	0%	100%
5	Other IIS Supply Cost Variance	45%	55%
8	Load Variance		
	Utility Customer	45%	55%
	Industrial Customers	45%	55%
10	Greenhouse Gas Credit Variance	45%	55%

The demand-and-energy approach to cost classification, under these assumptions, produces a cost allocation shift, relative to the energy-only approach, in the direction of the Utility customer of about $642 thousand dollars (0.1%), matched by an offsetting reduction in Island Industrial costs of $641 thousand (-1.4%) and an Island Rural allocated cost increase of about $1 thousand (effectively 0%). (See the rightmost columns of the table below.)

If the demand-and-energy approach represents a better estimate of the cost responsibility of each class than does the energy-only allocation, then a move to the demand-and-energy approach results in an appropriate small cost shift toward the Utility customer and away from the Island Industrial customers. The percentage shift is tiny for the Utility but noticeable for the Industrials. This shift corresponds with the hypothesis that the utility customer is more peak-coincident than are the Island Industrial customers. A summary of the results appears in Table 5.

The resulting percentage change in the overall customer bills (different from the change relative to the cost/bill shift described immediately above) is a bill increase of 5.7% for the Utility customer (up from 5.6%), a bill increase of 0.3% for the Island Industrials (down from 1.7%), and a residual "increase" of 0.4% for the Island Rural customers (unchanged). (Because the residual bill impact for the Island Rural customers is transferred to the Labrador Interconnected customers the actual bill change for the Island Rural customers is zero.) See the middle columns of the table for these impacts.

[11] Hydro classifies thermal costs as 100% demand-related, wind costs as 78% demand-related, and deems purchase classification to be based on system load factor.

Table 5
Bill Impact of SCVD Account Introduction
Under Alternative Cost Classification Approaches
Estimated 2025 Loads, 2025 Rates

Rate Class	**Base Bill**	**Bill Impact**					
		Energy-Only		Demand-and-Energy		D&E vs. E-Only	
	$Thousand	$Thousand	Percent	$Thousand	Percent	$Thousand	Percent
Utility	$634,575	$35,723	5.6%	$36,365	5.7%	$642	0.1%
Island Industrial	$45,458	$774	1.7%	$133	0.4%	-$641	-1.4%
Island Rural	$67,306	$254	0.4%	$253	0.4%	-$1	0.0%
Total	$747,338	$36,751	4.9%	$36,751	4.9%	$0	0.0%

The 2024 cost recovery obligation of an additional 4.9% exceeds Hydro's agreed domestic customer bill ceiling increase of 2.25%. As an exercise, we can constrain the *overall* increase in bills due to the addition of the SCVD Account to 2.25% (but permit larger increases for individual customers).[12] If we reduce the bill obligation by increasing the Rate Mitigation Fund receipts, but retain all other assumptions, then the bill increases are as presented in Table 6 below.

Table 6
Bill Impact of SCVD Account Introduction
Under Alternative Cost Classification Approaches
Estimated 2025 Loads, 2025 Rates, Constrained Bill Increase

Rate Class	**Base Bill**	**Bill Impact**					
		Energy-Only		Demand-and-Energy		D&E vs. E-Only	
	$Thousand	$Thousand	Percent	$Thousand	Percent	$Thousand	Percent
Utility	$634,575	$17,528	2.8%	$17,943	2.8%	$415	0.1%
Island Industrial	$45,458	-$917	-2.0%	-$1,330	-2.9%	-$413	-0.9%
Island Rural	$67,306	$204	0.3%	$203	0.3%	-$1	0.0%
Total	$747,338	$16,815	2.25%	$16,815	2.25%	$0	0.0%

The Utility customer bill increase becomes 2.8% under both approaches, the Island Industrial bills decrease by 2.05 under the energy-only approach and by 2.9% under the demand-and-energy approach. The Island Rural customer bills "increase" by 0.3% in both cases, following

[12] This is a simplification of the rule that domestic customer bills only would be subject to the 2.25% increase ceiling. Other classes may sustain higher increases. Also, this exercise is different from the actual rule that overall all-in domestic customer bills (including the SCVD account levy) cannot rise by more than 2.25% year-over-year through 2030. However, this exercise offers a simple example of constrained bill increases.

reallocation of the portion transferred to the Utility customer. (As above, the actual Island Rural bill increase is zero due to the transfer of the residual to the Labrador Interconnected customers.) Note that the Utility bill increase probably meets the constraints on domestic customers, since the excess over the 2.25% limit might plausibly be applied to business customers of the utility.

While this example is illustrative, there remains a question as to the variability around these impacts. Historically, the 2024 variance of an increase of $36.75 million is small compared to that of 2022 (about $191 million) but the 2022 amount contains no reductions for rate mitigation and is thus likely an overstatement. Additionally, Hydro's plan for the period following the next rate application is to keep the variance centered on zero, in expectation. This suggests that the 2024 variance might be a more plausible value for an average variance than the 2022 value.

5. FINDINGS

Hydro's new SCVD account comprehensively covers the cost variances associated with the Muskrat Falls project and the revenue variances that may occur, as well as consumption and customer activities' departures from forecast. Hydro could elect to recover/reimburse costs/credits based solely on energy consumption. This is a simple and well-founded practice in rider pricing bearing on generation-related costs, based on the jurisdictional review.

The simple example provided in this report suggests that a demand-and-energy cost allocation tied to Hydro's existing COS methodology might produce a slightly improved allocation of customer cost responsibility. While variances following the upcoming general rate application are conjectural, other than that they are expected to be centered on zero, past experience offers an indication of the possible scale of impact of the change in methodology. It appears that the bill reductions for Island Industrial customers arising from the use of the demand-and-energy approach to cost classification might be large enough to be noticeable.

Implementation of the demand-and-energy alternative would involve application of the existing COS methodology to the SCVD account components. Actual cost recovery could use demand-and-energy pricing for the Utility and Island Industrial customers, but an energy-only charge would like serve almost as well, with slight reductions in billing match to cost across Island Industrial customers, with high load factor customers being slightly overcharged and low load factor customers being slightly undercharged.

Attachment 2

Illustrative Example of Allocation Between Customer Classes

Long-Term SCVDA
Cost Variance Allocation Example
Energy only Allocator vs. Demand/Energy Allocators[1]

Cost Allocation

Component	Variance Allocations[2] Demand [A]	Energy [B]	Variances from TY[3] ($ million) [C]	Demand Allocation ($ million) [D] = [A] * [C]	Energy Allocation ($ million) [E] = [B] * [C]
Muskrat Falls Project Costs	45%	55%	5.5	2.5	3.0
Net Revenue from Exports	45%	55%	17.2	7.7	9.5
Transmission Tariff Revenue	45%	55%	(1.3)	(0.6)	(0.7)
Rate Mitigation Funding	45%	55%	38.0	17.1	20.9
Holyrood TGS	0%	100%	(3.4)	-	(3.4)
Utility Load	45%	55%	(6.8)	(3.1)	(3.8)
Industrial Load	45%	55%	(5.1)	(2.3)	(2.8)
Greenhouse Gas Credits Revenue	45%	55%	1.6	0.7	0.9
Other IIS Supply Cost:					
Thermal	100%	0%	0.2	0.2	-
Off - Island Purchases	45%	55%	-	-	-
On - Island Purchases	45%	55%	0.0	0.0	0.0
Wind	78%	22%	-	-	-
			45.8	**22.3**	**23.6**

Cost Allocation to Customer Balances (Based on Energy)

Customer	Energy (GWh)[4]	Customer Allocation[5] ($ million)	Reallocate Rural[6] ($ million)	Total[7] ($ million)
Newfoundland Power Inc.	5,938.91	38.8	2.8	41.6
Island Industrials	638.78	4.2	-	4.2
Island Rural	440.64	2.9	(2.8)	0.1
	7,018.32	**45.8**	**-**	**45.8**

Cost Allocation to Customer Classes (Based on Demand and Energy)

Customer	Demand (MW)[8]	Demand[9] ($ million)	Energy[10] ($ million)	Total Customer Allocation ($ million)	Reallocate Rural[6] ($ million)	Total[7] ($ million)
Newfoundland Power Inc.	16,156.8	19.7	19.9	39.7	2.7	42.4
Island Industrials	971.9	1.2	2.1	3.3	-	3.3
Island Rural	1,105.2	1.4	1.5	2.8	(2.7)	0.1
	18,233.9	**22.3**	**23.6**	**45.8**	**-**	**45.9**

Billing Impacts

Customer	2023 Billing	Energy Allocator Cost	Rate Impact	Demand and Enegy Allocator Cost	Rate Impact	Variance % Change	$ Change
Newfoundland Power							
Base Rate Revenue	522.3						
Project Cost Recovery Rider	46.7						
RSP Rider	11.6						
CDM	1.6						
	582.2	**41.6**	**7.1%**	**42.4**	**7.3%**	**0.1%**	**0.8**
Island Industrials							
Base Rate Revenue	23.7						
Project Cost Recovery Rider	-						
RSP Rider	4.9						
CDM	0.0						
	28.6	**4.2**	**15%**	**3.3**	**11.6%**	**-2.9%**	**(0.8)**
Total[11]		**45.7**		**45.7**			

[1] Numbers may not add due to rounding.
[2] Consistent with Schedule 1 Table 1.
[3] Variances calculated for illustrative purposes only. Assumes Test Year includes all components in base rates.
[4] 12 months-to-date energy.
[5] Customer Energy / Total Energy * [C] Total Variance from TY
[6] Hydro Rural Customer balance allocated between Newfoundland Power and Labrador Interconnected customers based on Test Year percentages approved for Rural Deficit Allocation. For the purpose of this illustrative example these allocations are equal to those approved in the 2019 Test Year of 96.1% for Newfoundland Power and 3.9% for Labrador Interconnected.
[7] Amount remaining in Island Rural is assigned to Labrador Interconnected and will be wrote-off to Hydro's net income (loss).
[8] The demand for Newfoundland Power Inc. equal to the sum of monthly billing demands, Island Industrials is equal to the maximum annual billing demand * 12, and Island Rural is equal to annual peak demand * 12.
[9] Customer Demand / Total Demand * [D] Demand Allocation
[10] Customer Energy / Total Energy * [E] Energy Allocation
[11] Excludes $0.1 million remaining for Island Rural which will be allocated to the Labrador Interconnected customers.

Schedule 2

Long-Term Supply Cost Variance Deferral Account – Definition

Newfoundland and Labrador Hydro
Long-Term Supply Cost Variance Deferral Account – Definition

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

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

Section A

1.0 Muskrat Falls Project ("Project") Cost Variances

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

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

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

Where:

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

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

B = Actual Purchased Power Expense from TFA Charges; and

B_T = Test Year Purchased Power Expense from TFA Charges.

2.0 Rate Mitigation Fund Variances

The Rate Mitigation Fund Variance will be calculated monthly based on the following formula:

$$(R_T – R)$$

Where:

R_T = Test Year Rate Mitigation ($); and

R = Actual Rate Mitigation ($).

3.0 Project Cost Recovery

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

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

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

$$(C - C_T)$$

Where:

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

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

5.0 Other Island Interconnected System Supply Cost Variance

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

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

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

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

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

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

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

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

$$D + E + F + G$$

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

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

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

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

F = Test Year Power Purchase Variances resulting from volume;

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

G = Variances based on firm energy purchases from CBPP;

> Where:
>
> G = (Actual CBPP Power Purchase Cost – Capacity Assistance Adjustment) – (Test Year CBPP Firm Energy Power Purchase Cost).
>
> "Capacity Assistance Adjustment" shall represent any change in fixed capacity assistance payments as a result of firm energy purchases from CBPP.

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

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

6.0 Net Revenue from Exports Variance

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

$$(H_T - H)$$

Where:

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

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

H = Actual Net Revenues from Exports ($).

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

Revenues from non-firm sales on the Island Interconnected System supplied by hydraulic generation will also be credited to the Net Revenue from Exports Variance component.

7.0 Transmission Tariff Revenue Variance

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

$$(I_T - I)$$

Where:

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

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

8.0 Load Variation

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

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

Where:

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

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

K_R = Firm Energy Rate, by customer class.

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

9.0 Rural Rate Alteration

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

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

Where:

N_T = Test Year Cost of Service rural rates;

N_A = Existing rural rates;

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

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

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

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

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

10.0 Greenhouse Gas Credit Revenues Variance

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

$$(T_T - T)$$

Where:

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

T = Actual Greenhouse Gas Credit Revenues ($).

Section B

1.0 Plan Balances

Separate plan balances for the Utility and Island Industrial customers will be maintained in this account. Transfers to the Utility balance and the Island Industrial customer balance will reflect the monthly customer allocations of supply variations in the account. Transfers to the Utility balance will also reflect the monthly adjustments for the Rural Rate Alteration.

2.0 Financing Costs

Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

3.0 Monthly Customer Allocation

Each month the year-to-date variances in the Long-Term Supply Cost Variance Deferral Account will be allocated to demand and energy based on a consistent allocation methodology approved in the Test Year Cost of Service Study for each component, or otherwise approved by the Board for the allocation of the balances in this account.

<u>3.1 Energy Allocation</u>

Each month the energy costs will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the energy costs which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion as the Rural Deficit is allocated in the most recently approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the plan and written off to Hydro's net income (loss).

3.2 Demand Allocation

Each month the demand costs will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from year-to-date kW for: Utility Firm invoiced monthly billing demand, Industrial Firm maximum invoiced demand multiplied by year-to-date months, and Rural Island Interconnected maximum peak demand multiplied by the year-to-date months.

The portion of the demand costs which are initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion as the Rural Deficit is allocated in the most recently approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

4.0 Balance Disposition

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

5.0 Balance Transfers

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

Affidavit

newfoundland labrador hydro

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 Sections 58, 71, and 80 of the *Act*, for the approval of a deferral account, modifications to Hydro's Cost of Service, and an accounting deviation related to the long-term plan for the current Supply Cost Variance Deferral Account ("SCVDA").

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 and 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 April 2025, before me:

Barrister, Newfoundland and Labrador
Witnessed through the use of audio-visual technology in accordance with the *Commissioners for Oaths Act* and *Commissioners for Oaths Regulations*

Dana Pope, CPA (CA), MBA