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May 27, 2026

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

Attention: Mike McNiven
Board Secretary

Re: 2026 General Rate Application

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") 2026 General Rate Application ("GRA") for approval of Hydro's 2027 Test Year forecast costs and customer rates ("Application").

Background

Hydro's most recent GRA, filed in 2017, was based on a 2019 Test Year. Since that time, Hydro's operating and regulatory environment has undergone a material change. Following the issuance of the Board of Commissioners of Public Utilities ("Board") Order No. P.U. 15(2020), which approved the deferral of Hydro's next GRA pending key developments, Hydro provided regular quarterly updates to the Board. The reporting continued through the commissioning of the Muskrat Falls Hydroelectric Generating Facility, the Labrador Transmission Assets ("LTA"), the Labrador-Island Link ("LIL"), and the establishment of the Government of Newfoundland and Labrador's ("Government") rate mitigation plan. During this period, the Board also approved a number of regulatory accounting mechanisms, deferral accounts, and related directives to be addressed in Hydro's next GRA.

With the Muskrat Falls Assets now fully in service, Government rate mitigation plan in effect, and several related proceedings having reached resolution or advanced maturity, Hydro is filing this Application for the 2027 Test Year to establish updated rates and to address outstanding matters.

Effective January 1, 2025, Hydro and Nalcor Energy were amalgamated pursuant to the *Hydro Corporation Act, 2024*, resulting in a single continued Crown utility. The amalgamation did not alter Hydro's status as a public utility subject to regulation by the Board under the *Electrical Power Control Act, 1994* ("EPCA"), and the *Public Utilities Act* ("Act"), nor did it change the statutory framework governing rate setting, cost recovery, or regulatory oversight. Hydro continues to operate its regulated electricity business in accordance with Board direction and applicable legislation. This Application has been structured to reflect this corporate change, while maintaining continuity with established regulatory practices and prior Board Orders.

The Application

The Application and pre-filed supporting materials are provided in three volumes:

Volume I:	Application, Company Evidence and Schedules, including this letter, a list of abbreviations, the Application, and Hydro's supporting evidence.

Volumes II and III: Exhibits to the evidence, including studies, reports, and other supporting materials relied upon by Hydro in support of the Application.

Hydro's Proposals

The Application reflects Hydro's costs of providing electricity service in the current operating environment, following the commissioning of the Muskrat Falls Hydroelectric Generating Facility, the LTA, and the LIL. For the first time in a GRA, Hydro has included Muskrat Falls supply costs within its test year revenue requirement. Although these costs are exempt from prudence review pursuant to Order in Council OC2013-343 and the Muskrat Falls Project Exemption Order, Hydro has included detailed evidence regarding these costs in the interest of transparency and accountability, and to support a comprehensive understanding of the costs underlying customer rates.

The Application also incorporates Government's rate mitigation plan, which limits the rate impacts experienced by customers on the Island Interconnected System. Rate mitigation affects the rates ultimately charged to customers but does not determine the prudence or recoverability of Hydro's costs. Those matters remain subject to review through the regulatory process. Hydro's proposals in this Application are structured to reflect this distinction.

Hydro's 2027 Test Year was selected having regard to the passage of time since Hydro's last GRA and the significant changes to Hydro's operating environment over that period. Given the elevated inflation experienced since the 2019 Test Year, Hydro has used its 2024 audited results as the primary historical comparator for the 2027 Test Year. While 2025 is not used as a comparator year for test year development, Hydro acknowledges the importance of providing the most current information available and will file supplementary material once the final audited 2025 actual results become available, following assent in the House of Assembly.

Customer Rates

Hydro's Application seeks approval of customer rates designed to recover its proposed 2027 Test Year revenue requirement in a manner that is consistent with Government's rate mitigation plan and applicable legislative and regulatory requirements. Proposed rates are structured to give effect to Government direction that rate increases attributable to Hydro's costs on the Island Interconnected System be targeted to approximately 2.25% annually for Domestic customers, with rates for other Island Interconnected System customer classes structured in a manner compatible with this objective.

Consistent with this direction, Hydro is proposing final rates effective July 1, 2027 that reflect its mitigated revenue requirement. The rate proposals are designed to recover Hydro's costs in a just and reasonable manner while substantially limiting customer rate impacts through the application of rate mitigation funding.

Adjustments to rates on the Labrador Interconnected System, which have not been updated since the 2019 Test Year, are also proposed through this Application. Hydro is proposing that increases for these customers be smoothed over multiple years, beginning with a 2.25% increase effective July 1, 2027, to mitigate bill impacts while reflecting the underlying cost of service.

Hydro is also proposing an increase to the wholesale rate charged to its Utility customer, Newfoundland Power Inc. ("Newfoundland Power"), effective July 1, 2027. When flowed through to retail customers of Newfoundland Power, this change results in an estimated average Domestic customer rate increase of approximately 2.25%, consistent with Government's rate mitigation plan. Rate mitigation affects the rates ultimately paid by customers but does not alter Hydro's entitlement to recover its prudent costs, which remain subject to the Board's review.

Regulatory Accounting

In addition to its proposed rates, Hydro is seeking approval of certain rate design changes intended to improve cost causation, enhance rate equity, and reflect changes in system configuration and customer usage patterns since Hydro's last GRA. This includes a proposed rate design for Island Industrial customers incorporating an hours-of-use based two-block energy structure, intended to better align pricing with marginal cost and provide improved incentives for efficient demand management.

These proposals have been developed having regard to Hydro's updated Cost of Service Study filed as part of the Application.

The Cost of Service Study is predicated on principles and assumptions approved in Board Order No. P.U. 37(2019), and on an agreement reached with the intervenors to Hydro's 2025 Cost of Service Methodology Review Application regarding the majority of the proposals made by Hydro in that application ("2025 Cost of Service Settlement Agreement"). A fully executed copy of the 2025 Cost of Service Settlement Agreement will be filed under separate cover in this proceeding.

As part of the 2025 Cost of Service Settlement Agreement, the parties agreed to defer the following issues to this GRA:

- Classification of the Holyrood Thermal Generating Station ("Holyrood TGS") generation costs;
- Classification of Holyrood TGS fuel costs; and
- The implementation of a 64 MW Hydraulic Credit for Newfoundland Power, with the process for determination of the thermal generation credit to remain unchanged.

Hydro's proposals for both these issues are set out within the Application.

Hydro's rate design proposals include, among other things, modifications for select customer classes and updates to specific rate schedules and service provisions. These changes are intended to better align rates with the cost to serve, while remaining consistent with Government direction, Board precedent, and keeping affordability top of mind and avoiding significant impacts on customers by enacting smaller, continuous, and incremental steps. Detailed evidence in support of Hydro's rate design proposals, including cost of service results and bill impact analyses, is provided in Chapter 6 of the Application and the associated schedules.

Summary of Regulatory Accounting Proposals

Hydro seeks approval of a number of regulatory accounting proposals required to address outstanding matters from prior Board Orders and to reflect changes in Hydro's operating and financial environment, including:

- Approval of Hydro's proposed 2027 Test Year revenue requirement, rate base, capital structure, and rate of return;
- Continuation of approved methodologies for working capital allowance, depreciation rates, and cost escalation, as set out in the evidence;
- Disposition and amortization of balances in existing regulatory deferral accounts, including accounts related to business system transformation initiatives, Board and intervenor costs, conservation and demand management programs, and other previously approved deferrals;

- Amortization and recovery of the Muskrat Falls Power Purchase Agreement Sustaining Capital Deferral Account over the service life of the assets, with inclusion of the deferral balance in rate base;
- Establishment of a Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027, to capture future supply cost variances on a prospective basis;
- Recovery of approved regulatory and GRA hearing costs over appropriate amortization periods;
- Implementation of approved cost of service methodology changes and remaining cost of service matters deferred to this Application; and
- Approval of related accounting deviations and deferral account treatments necessary to give effect to Government's rate mitigation framework.

Hydro believes that the proposed rates and rate design changes, taken together, appropriately balance the objectives of cost recovery, customer affordability, rate stability, and regulatory efficiency, and are reasonable and necessary in light of Hydro's statutory mandate and current operating environment.

The Application and supporting evidence are filed in accordance with the *Act*, the *EPCA*, and prior Board Orders. Hydro believes that the proposed revenue requirement, rates, and associated accounting and regulatory proposals are reasonable, necessary, and consistent with its statutory obligation to provide safe, reliable, environmentally responsible electricity service at the lowest possible cost.

Process and Related Matters

As part of the evidence to the Application, Hydro has provided a report that contains commercially sensitive information pertaining to Hydro's Industrial customers. This report, provided in Volume III, Exhibit 17, has been redacted and Hydro requests that this information be kept confidential and not be made publicly available. A version of the Application with an unredacted version of the report is being provided to the Board on a confidential basis; the parties will be provided with a version in which this information has been redacted. Hydro requests that the Board use the redacted version for posting to its website.

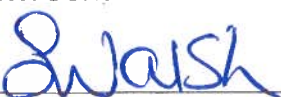
A copy of the Application containing the redacted report will be posted to Hydro's website at www.nlhydro.com in the coming days.

We trust you will find the enclosed Application to be in order.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



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2026 General Rate Application

Volume I: Application, Company Evidence and Schedules

May 2026

An application to the Board of Commissioners of Public Utilities



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Abbreviations



Abbreviations

Term	Definition
A	Actual
AACE	Association for the Advancement of Cost Engineering
<i>Act</i>	<i>Public Utilities Act</i>
BDE	Bay d’Espoir
BIF	Bishops Falls
Board	Board of Commissioners of Public Utilities
Braya	Braya Renewable Fuels
CA Energy	Christensen Associates Energy Consulting
CAT	Cat Arm
CBA	Capital Budget Application
CBPP	Corner Brook Pulp and Paper Limited
CDM	Conservation and Demand Management
CF(L)Co	Churchill Falls (Labrador) Corporation Limited
Churchill Falls	Churchill Falls Hydroelectric Generating Facility
CIAC	Contributions in Aid of Construction
Concentric	Concentric Advisors, Inc.
CT	Combustion Turbine
DAFOR	Derated Adjusted Forced Outage Rate
DAUFOP	Derated Adjusted Utilization Forced Outage Probability
Deloitte	Deloitte LLP
DLK	Deer Lake

Newfoundland and Labrador Hydro – 2026 General Rate Application
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Term	Definition
Dunksy	Dunsky Energy + Climate Advisors
<i>EPCA</i>	<i>Electrical Power Control Act, 1994</i>
EqFOR	Equivalent Forced Outage Rate
F	Forecast
FTE	Full-Time Equivalent
GCL	Granite Canal
GDP	Gross Domestic Product
GF	Grand Falls
GNP	Great Northern Peninsula
Government	Government of Newfoundland and Labrador
GRA	General Rate Application
Grant Thornton	Doane Grant Thornton, LLP
GT	Gas Turbine
GWh	Gigawatt Hour
HLK	Hinds Lake
Holyrood TGS	Holyrood Thermal Generating Station
HPS	High-Pressure Sodium
HRD	Holyrood
HVDC	High-Voltage Direct Current
HWD	Hardwoods
Hydro	Newfoundland and Labrador Hydro
Intercompany Guidelines	Intercompany Transactions Costing Guidelines
IOC	Iron Ore Company of Canada

Newfoundland and Labrador Hydro – 2026 General Rate Application
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Term	Definition
IT	Information Technology
km	Kilometre
KPMG	KPMG LLP
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LED	Light-Emitting Diode
LIL	Labrador-Island Link
Linde	Linde Canada Inc.
LTA	Labrador Transmission Assets
Marathon	Marathon Gold Corporation
Mbbls	One Thousand Barrels
MW	Megawatt
MWh	Megawatt Hour
Nalcor	Nalcor Energy
Newfoundland Power	Newfoundland Power Inc.
NLSO	Newfoundland and Labrador System Operator
OC	Order in Council
P50	50th Percentile
P90	90th Percentile
Pilot Agreement	Pilot Agreement for the Optimization of Hydraulic Resources
PPA	Power Purchase Agreement
PRV	Paradise River

Newfoundland and Labrador Hydro – 2026 General Rate Application
Abbreviations

Term	Definition
Q	Quarter
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEM	System Equipment and Maintenance
Soldiers Pond	Soldier's Pond Converter Station
Southlea	Southlea Group LP
SVL	Stephenville
Tacora	Tacora Resources Inc.
Teck	Teck Resources Limited
TWh	Terawatt-hour
TwinCo	Twin Falls Power Corporation
TY	Test Year
UFLS	Under-Frequency Load Shedding
USL	Upper Salmon
Vale	Vale Newfoundland and Labrador Limited

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

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2027.

To: The Board of Commissioners of Public Utilities

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro, 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. Pursuant to 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. On May 7, 2019, in Order No. P.U. 16(2019), the Board ordered that Hydro should file its next GRA by September 30, 2020 for rates based on a 2021 Test Year. On April 15, 2020, Hydro filed an application requesting the Board's approval to delay the filing of its next GRA and that the proposed rates be based on a 2021 Test Year and additional test years, if required. That application proposed that Hydro's GRA be delayed from September 30, 2020, to no later than nine months after the date upon which both the revised financial structure for the Muskrat Falls PPA and Government's rate mitigation plan have been finalized and publicly communicated.
4. In Order No. P.U. 15(2020), the Board found that it was appropriate to delay the filing of Hydro's GRA beyond September 30, 2020, and that it was premature to make a determination as to the test year(s) to be used in determining customer rates. The Board ordered that Hydro was not required to file its GRA on September 30, 2020, for rates based on a 2021 Test Year and that Hydro was to file quarterly updates with respect to the filing of its next GRA.

5. Hydro continued to file the quarterly updates through the commissioning of the Muskrat Falls Hydroelectric Generating Facility,¹ the LIL,² and the establishment of the Government's rate mitigation plan.³ Hydro's update of June 27, 2025 noted that in addition to the commissioning of the Muskrat Falls Hydroelectric Generating Facility, the LIL, and Government's establishment of the rate mitigation plan, Hydro had been reviewing its committed filings and had determined that to promote regulatory efficiency and to streamline the process for the GRA, Hydro was planning to submit certain reports and applications to bring resolution to various issues in advance of the GRA. Hydro advised that it would file its GRA in the first quarter of 2026.
6. In Order No. P.U. 29(2019), the Board approved the deferral account for the Board's external consulting costs and approved intervenor costs associated with the *Reliability and Resource Adequacy Study Review*. The Order stated that Hydro shall apply for recovery of costs charged to the deferral account through its next GRA. In 2021, the account definition was expanded in Board Order No. P.U. 8(2021) to include Hydro's external costs for professional services and contractors related to the assessment to determine the potential long-term viability of the Holyrood TGS. Hydro's proposal for recovery of the deferral account balance is contained herein.
7. In Order No. P.U. 33(2021), the Board approved Hydro's Muskrat Falls PPA Sustaining Capital Deferral Account effective on the date upon which Hydro was required to begin payments under the Muskrat Falls PPA.⁴ The Board noted in its Order that a decision on how the payments would be recovered from customers was to be determined in Hydro's next GRA.
8. In Order No. P.U. 4(2022), the Board approved certain deferral accounts, changes to existing deferral accounts, and an accounting deviation associated with the commissioning of the Muskrat Falls Project. These approvals included:
 - a) The Supply Cost Variance Deferral Account, with an effective date of November 1, 2021;

¹ The final unit of the facility was released for service on November 22, 2021, and thus the facility was considered commissioned as of that date.

² The LIL was deemed commissioned as of April 13, 2023.

³ Government's finalization of the rate mitigation plan was announced in May 2024.

⁴ The Muskrat Falls Hydroelectric Generating Facility was commissioned in November 2021, upon which Hydro was required to begin making payments under the Muskrat Falls PPA.

- b) The Rate Stabilization Plan Rules for Balance Disposition with an effective date of November 1, 2021;
 - c) The Revised Energy Supply Cost Variance Deferral Account: Rules for Balance Disposition with an effective date of November 1, 2021;
 - d) The Holyrood Conversion Rate Deferral Account: Rules for Balance Disposition, with an effective date of November 1, 2021;
 - e) The discontinuance of the existing Rate Stabilization Plan Rules and the existing rules related to the Revised Energy Supply Cost Variance Deferral Account and Holyrood Conversion Rate Deferral Account as of November 1, 2021; and
 - f) The Holyrood TGS Accelerated Depreciation Deferral Account with an effective date of January 1, 2022.
9. In Order No. P.U. 27(2022), the Board approved the recovery of actual and forecast deferred costs up to the end of 2022 associated with the Enterprise Resource Planning like-for-like implementation and the Information Management Program, estimated to be \$6.7 million, through customer rates to be established in Hydro's next GRA.
 10. In Order No. P.U. 37(2022), the Board approved the deferral of CDM costs incurred for customers on the Labrador Interconnected System in the CDM Cost Deferral Account, including a portion of the Rural Deficit allocation related to CDM investments for Hydro Rural customers, and to increase the amortization period of annual CDM costs from seven to ten years effective as of January 1, 2023 for both historical balances and annual charges.
 11. In Order No. P.U. 33(2023), the Board approved the Electrification Cost Deferral Account definition, with an effective date of January 1, 2023.
 12. In Order No. P.U. 1(2024), the Board approved amendments to the Holyrood TGS Accelerated Depreciation Deferral Account effective January 1, 2024, and directed Hydro to file a report on the activity and operation of the deferral account with its next GRA. The report is enclosed as Exhibit 11.

13. In Order No. P.U. 1(2025), the Board approved the proposed wholesale rate to be charged to Newfoundland Power effective January 1, 2025.
14. The Board directed Hydro to file a methodology for updating the wholesale rate no later than its next GRA, or April 15, 2026. Hydro filed an application for an extension to the filing date for the methodology application, which is under consideration by the Board as of the filing date of this application.
15. In Order No. P.U. 21(2025), the Board approved the Disposition of Balances within the Hydraulic Resources Optimization Deferral Account.
16. In Order No. P.U. 32(2025), the Board approved the Capitalization of General Expenses Deferral Account.
17. In Order No. P.U. 34(2025), the Board approved an accounting deviation for rate mitigation funding to allow for the reporting and presentation of the rate mitigation funding as revenue by Hydro, effective January 1, 2025.
18. In Order No. P.U. 35(2025), the Board approved a deferral account to enable deferral and recovery of costs incurred in implementing cloud-based software solutions.
19. In Order No. P.U. 37(2019), the Board approved Hydro's proposals in its 2018 Cost of Service Methodology Review, as set out in a Settlement Agreement among the parties, directed Hydro to file a number of reports and proposals regarding outstanding issues related to the Cost of Service in Hydro's next GRA.
20. On August 22, 2025, Hydro applied to the Board for modifications to Hydro's Cost of Service Methodology ("2025 Cost of Service Methodology Application"), reflecting Board Order No. P.U. 37(2019) and addressing other outstanding methodology issues, required for the Cost of Service to be filed in Hydro's GRA.

21. The Cost of Service Study is predicated on principles and assumptions approved in Board Order No. P.U. 37(2019), and on an agreement reached with the intervenors to Hydro's 2025 Cost of Service Methodology Application ("2025 Cost of Service Settlement Agreement").⁵
22. Two particular issues that Hydro has identified as items that will not achieve consensus within the 2025 Cost of Service Methodology Application have been included in this GRA for review and are included in Hydro's proposals herein.
23. Under the authority of the *EPCA* in OC2009-063, the Lieutenant Governor in Council directed the Board to set the same target return on equity to be used in the calculation of the return on rate base for all future GRA filed by Hydro as was most recently set for Newfoundland Power; that Hydro would earn a return on equity on its entire rate base including amounts related to rural assets; and that Hydro would be permitted to have the proportion of equity in its capital structure up to a maximum of the same approved for Newfoundland Power.
24. In Order No. P.U. 49(2016), the Board determined that Hydro's target return on equity should be subject to an adjustment process in the years between GRAs so that it continues to be the same as Newfoundland Power's return on equity.
25. In Order No. P.U. 30(2019), the Board approved the definitions of the Excess Earnings Account and the Return on Equity Rate Change Deferral Account, including the methodology to determine the change in Hydro's revenue requirement by rate class and rate design resulting from a return on equity change.
26. In Order No. P.U. 3(2025), the Board approved an increase in Newfoundland Power's return on equity from 8.50% to 8.60%, effective January 1, 2025.
27. In Order No. P.U. 10(2025), the Board approved:
 - a) A return on equity of 8.60% effective January 1, 2025;
 - b) A return on rate base of 5.45% effective January 1, 2025;
 - c) A revised 2019 Test Year revenue requirement of \$643,504,433;

⁵ A fully executed copy of the 2025 Cost of Service Settlement Agreement will be filed under separate cover in this proceeding.

- d) A revised Return on Equity Rate Change Deferral Account definition effective January 1, 2025;
 - e) A revised Excess Earnings Account definition effective January 1, 2025; and
 - f) A deviation to the methodology to update the rate structure for Newfoundland Power, Island Industrial customers, Hydro Rural Labrador Interconnected customers, and Labrador Industrial customers to reflect a return on equity of 8.60% in the next test year.
28. On May 7, 2024 in OC2024-062, under the authority of the *Hydro Corporation Act, 2007*, the Lieutenant Governor in Council directed the Board of Directors of Hydro to “structure any application for utility rate increases such that retail rate increases to domestic rate class customers attributable to Newfoundland and Labrador Hydro shall be targeted at 2.25 per cent per year annually up to and including 2030” for each rate application filed with the Board relating to the period up to and including the year 2030. The OC further directed that any additional funding required for Hydro to mitigate the Muskrat Falls Project costs for customers subject to Island Interconnected System rates, to achieve the targeted rate increase for the period up to and including 2030, be through Hydro’s sources, to the extent possible, and for Hydro to retire the 2023 Supply Cost Variance Deferral Account balance of \$271 million over the 2024–2026 period.
29. Under the authority of the *Energy Corporation Act* and the *Corporations Act*, in OC2024-063, the Lieutenant Governor in Council directed the Board of Directors of Nalcor Energy that any additional funding required for Hydro to mitigate the Muskrat Falls Project costs or to retire the 2023 Supply Cost Variance Deferral Account balance of \$271 million be through Nalcor Energy’s sources.
30. The first rate change implemented pursuant to the above-noted OCs became effective August 1, 2024, as part of Hydro’s application for July 1, 2024 Utility Rate Adjustments approved in Board Order No. P.U. 15(2024).
31. In December 2024, the *Hydro Corporation Act, 2007*, was repealed and replaced by the *Hydro Corporation Act, 2024*, amalgamating Nalcor Energy and Hydro effective January 1, 2025.

B. Hydro's Proposals

32. Hydro makes this application under the *EPCA* and under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80 of the *Act*, and requests approval of the following:

Revenue Requirement

- (i) Hydro's proposal to have its 2027 Test Year revenue requirements, and resulting rates, reflect the costs of providing electricity service and Government's rate mitigation plan as described in Chapters 1 through 6 of the evidence filed in support of this application.
- (ii) For the purposes of calculating Hydro's 2027 Test Year:
 - a) A 2027 Test Year revenue requirement of \$797,713,000;
 - b) A 2027 forecast average rate base of \$2,802,095,000;
 - c) A rate of return on rate base of 4.88% in a range of 4.68% to 5.08%;
 - d) Hydro's forecast capital structure for 2027, with a weighted average cost of capital of 4.88%; and
 - e) the Holyrood conversion rate of 563 kWh per barrel.

Regulatory Accounting

- (iii) Hydro's continued use of the working capital allowance methodology, as set out in Chapter 5 of the evidence in support of this application and the separation of Muskrat Falls supply costs and related transactions to be allocated to the Island Interconnected System.
- (iv) Hydro's proposed depreciation rates and methodology, as set out in Chapter 5 and Exhibits 7 and 8 of the evidence in support of this application.
- (v) The disposition and amortization of balances in existing regulatory deferral accounts, as set out in Chapter 5 of the evidence in support of this application. More particularly:

- a) The amortization and recovery of the Business Systems Transformation Program Deferral Account balance of \$14.5 million, over a period of eight years, commencing January 1, 2027, at a rate of \$1.8 million per year;
- b) The disposition of the Frequency Converter Depreciation Deferral Account balance of \$1.6 million due from customers through disposition or transfer to the Supply Cost Variance Deferral Account for Island Interconnected System customers, and through transfer to the respective Revenue Deficiency deferral accounts for Labrador customers;
- c) The amortization and recovery of the Phase Two Hearing Costs Deferral Account balance as at January 1, 2027 of \$1.7 million, over a period of eight years commencing in 2027, at \$0.2 million per year;
- d) The amortization and recovery of the *Reliability and Resource Adequacy Study Review* forecast December 31, 2027 deferral account balance, prior to amortization, of \$5.1 million over a period of eight years commencing in 2027 at \$0.6 million per year;
- e) The amortization of the Muskrat Falls PPA Sustaining Capital Deferral Account based on the composite depreciation rate of the Muskrat Falls Hydroelectric Generating Facility and Labrador Transmission Assets of 1.42% and 1.71%, respectively, as recommended by Concentric in their memorandum attached as Exhibit 9 and in accordance with the revised deferral account definition in Exhibit 10 to the evidence in this application;
- f) The recovery of the Electrification Cost Deferral Account balance forecast at December 31, 2026, in accordance with the proposed definition included in Exhibit 10, which is consistent with the recovery of the CDM Cost Deferral Account. Amortization of \$0.1 million to be recovered in the 2027 Test Year through a rate rider;
- g) The forecast Return on Equity Rate Change Deferral Account balance as of January 1, 2027 related to Labrador Industrial customers in the amount of \$11,288, and Hydro Rural Labrador Interconnected customers in the

amount of \$44,572, be transferred to the respective Revenue Deficiency deferral accounts to be recovered in customer rates; and

- h) Deferral and recovery of external GRA hearing costs, estimated to be \$1.5 million, with amortization of these costs occurring over four years commencing in 2027.
- (vi) The creation of a new Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027, with allocations among customer classes based on the latest Cost of Service Study approved by the Board and interest calculated based on the weighted average cost of capital in Hydro's latest approved test year. Further information regarding the deferral account is contained in Chapter 5 of the evidence filed in support of this application, with the proposed account definition included in Exhibit 10. The approach for disposition or recovery of deferral account balances will be addressed in a future application to the Board.
- (vii) The creation of a Rural Labrador Interconnected – Revenue Deficiency Deferral Account to record the revenue deficiency/sufficiency each month until the balance in the account is settled. Further information regarding the proposed deferral account is contained in Chapter 6 of the evidence filed in support of this application, with the proposed account definition included in Exhibit 10.

Cost of Service Methodology

- (viii) The continuation of the cost of service treatment approved in Board Order No. P.U. 30(2019) for the Holyrood TGS and Holyrood TGS fuel costs, including:
 - a) The classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor; and
 - b) Holyrood TGS fuel costs be classified as 100% energy as discussed in Chapter 6 and Exhibit 14 of the evidence to this application.
- (ix) The implementation of a 64 MW Hydraulic Credit for Newfoundland Power, with the process for determination of the thermal generation credit to remain unchanged, as discussed in Chapter 6 and Exhibit 15 of the evidence to this application.

- (x) The classification of purchases of wind generation on the Island Interconnected System as 43% demand and 57% energy, as discussed in Chapter 6 and Exhibit 16 of the evidence to this application.

2027 General Rate Proposals

- (xi) Hydro's 2027 proposed rates for Newfoundland Power, effective July 1, 2027, as described in Chapter 6 of the evidence filed in support of this application, specifically:
 - a) A Demand rate of \$5.50 per kW of billing demand per month;
 - b) An increase in the First Block Energy rate to 11.815 cents per kWh;
 - c) A decrease in the Second Block Winter Energy rate to 8.958 cents per kWh; and
 - d) An increase in the Second Block Non-Winter Energy rate to 3.480 cents per kWh.
- (xii) The continuation of the curtailable credit of 12 MW utilized in computing the billing demand for Newfoundland Power, as discussed in Chapter 6 of the evidence in support of this application.
- (xiii) The discontinuance of the Firming-Up Charge of 2.882¢ per kWh, currently in place to firm up secondary energy purchased from CBPP and resold to Newfoundland Power as firm energy, as discussed in Chapter 6 of the evidence in support of this application.
- (xiv) Hydro's proposed 2027 rates for the Island Industrial customers, effective July 1, 2027, as described in Chapter 6 of the evidence in support of this application, specifically:
 - a) The implementation of hours of use rate design, utilizing a 300-hours of use block structure;
 - b) A Demand rate of \$5.50 per kW of billing demand per month;
 - c) A first block energy price of 6.694 cents per kWh;

- d) A seasonal energy second block price for winter of 8.889 cents per kWh;
 - e) A seasonal energy second block price for non-winter of 3.285 cents per kWh;
 - f) Annual specifically assigned charges as follows:
 - i. CBPP – \$5,822;
 - ii. Braya – \$103,152;
 - iii. Marathon – \$9,302;
 - iv. Teck – \$9,950;
 - v. Vale – \$285,041; and
 - g) The retention of the previously approved calculation for the Island Industrial customer Non-Firm Rate energy charge, with an update for the loss factor to the five-year average Island Interconnected System losses, from 3.34% to 3.44%.
- (xv) Discontinuation of the Island Industrial Wheeling rate for Island Industrial customers.
- (xvi) An overall increase of 8.54% for Rural Labrador Interconnected customers, with the exception of Street and Area Lighting, as set out in Chapter 6 of the evidence provided with this application, effected through a phased-in approach of an annual increase of 2.25% each year for four years.
- (xvii) Rates for Street and Area Lighting on the Labrador Interconnected System, as discussed in Chapter 6 and Schedule E-II of the evidence provided with this application.
- (xviii) That Hydro's proposed demand rate and revised rate design for Labrador Industrial Transmission, as set out in Chapter 6 of the evidence in support of this application, be approved effective July 1, 2026, including:
 - a) A Transmission Demand rate for Labrador Industrial customers of \$2.00 per kW of billing demand per month; and

- b) Annual specifically assigned charges to recover operating and maintenance costs associated with the specifically assigned transmission assets for each customer as follows:
 - i. Tacora – \$11,058; and
 - ii. IOC – \$33,697.

Revenue Deficiencies

- (xix) Hydro's proposal for rates based on a 2027 Test Year with anticipated rate implementation on July 1, 2027, will result in a revenue deficiency for the first six months of 2027, as detailed in Chapter 6 of the evidence in support of this application. Hydro proposes to recover revenue deficiencies by customer as follows:
 - a) Transfer of the Revenue Deficiency of \$60.1 million arising from the timing of implementation of rates for Newfoundland Power to the Supply Cost Variance Deferral Account;
 - b) Transfer of the Revenue Deficiency of \$2.7 million arising from the timing of implementation of rates for Island Industrial customers to the Supply Cost Variance Deferral Account;
 - c) Amortization of the Revenue Deficiency of \$165,000 resulting from the increase in rates to Government customers on Isolated Diesel systems over a period of 42 months and recover from customers through increased base rates;
 - d) Transfer of the monthly Revenue Deficiency/Sufficiency arising from rates for the Rural Labrador Interconnected customers to the proposed Revenue Deficiency Deferral Account for Labrador Interconnected Rural customers; and
 - e) Amortization of the Revenue Deficiency of \$1.8 million associated with Labrador Industrial customers over a period of 42 months to be recovered from customers through a GRA Recovery Rider, with the allocation as proposed within the GRA Recovery Rider.

(xx) The proposed amendment to rules and regulations governing service, as set out in Chapter 6 and Exhibit 19 of the evidence in support of this application, be approved effective July 1, 2027, including the following changes:

a) Modification of the definition of "Generation Credit" to reflect the change in calculation of the Hydraulic Credit to Newfoundland Power, testing requirements for thermal and hydraulic, and criteria for the Generation Credit reflected in billing demand.

(xxi) That upon hearing this application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

C. Reasons for Approval

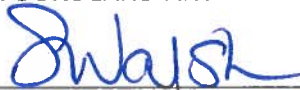
33. Approval by the Board of the proposals in this application will permit cost recovery through customer rates as provided for, and intended by, the *Act*, the *EPCA*, and the Orders of the Board set out in the application.

D. Communications

34. 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 27th day of May 2026.

NEWFOUNDLAND AND LABRADOR HYDRO



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

Affidavit



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

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2027.

AFFIDAVIT

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

- 1) I am Vice President, Regulatory Affairs & Stakeholder Relations for 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 27th day of May 2026, before me:



Barrister, Newfoundland and Labrador



Dana Pope, CPA (CA), MBA

Chapter 1

Overview



Chapter 1: Overview

1.1 Introduction

As a Crown corporation and regulated public utility, Hydro is accountable to the people and customers of Newfoundland and Labrador. Hydro operates transparently within the regulatory framework, engages customers and stakeholders, and applies sound utility and business practices to deliver reliable, least-cost service in an environmentally responsible manner. The 2026 GRA enables customers throughout Newfoundland and Labrador an opportunity to review the costs of providing electricity service in the current environment.

As a Crown utility, Hydro is also accountable to its shareholders and implements public policies and Government direction, as required. Hydro's decisions are appropriately subject to public scrutiny; Hydro's regulated operations are also subject to the oversight of the Board under the Act.

Since its last GRA, Hydro has prudently managed its operating costs. Hydro's 2027 Test Year forecast operating costs are approximately \$17 million below the 2019 Test Year forecast in real dollars.

System investments directly affect customer rates, reliability, and electricity supply. On an annual basis, Hydro files its CBA, carefully considering its annual capital investment portfolio to ensure its proposed programs and projects are those which are most critical to supporting the operation of Hydro's system.¹

The Muskrat Falls Hydroelectric Generating Facility, the Labrador Transmission Assets and the Labrador-Island Link (collectively known as the "Muskrat Falls Assets") provide customer benefits by improving system reliability and export/import capability, enabling significant reductions in Holyrood TGS generation and fuel usage, as included in the 2027 Test Year. This application incorporates Muskrat Falls supply costs within Hydro's revenue requirement for the first time since assets were commissioned. Through Government's rate mitigation plan, Hydro's 2027 Test Year revenue requirement has been mitigated to approximately \$798 million, and Hydro's portion of Domestic customer annual rate increases on the Island Interconnected System is limited to a targeted 2.25%.²

¹ Hydro deferred or cancelled over 30 projects in preparing its 2026 CBA, which corresponds to an estimated \$18.5 million in capital investment.

² Other rate classes on the Island Interconnected System who are supplied by Muskrat Falls (including Island Industrial Customers and Hydro's Rural customers) will also be subject to rate mitigation.

Even with Government's rate mitigation measures substantially limiting the rate increases experienced by many customers, it remains necessary for Hydro to file a GRA. Government's rate mitigation applies to Island Interconnected System rates. Rate mitigation affects what customers ultimately pay, but it does not determine which costs are prudent or what Hydro is entitled to recover; that determination occurs through the regulatory process.

Rates on the Labrador Interconnected System are only updated through Hydro's GRAs; therefore, rates have been unchanged since 2019 and will be updated through this application. In between test years, capital additions on the system and prudent increases in operating costs impact the cost of service for customers. Similar to the Island Interconnected System, Hydro is proposing that annual increases in rates for customers on the Rural Labrador Interconnected System also be limited to 2.25%.

The 2026 GRA allows the Board, intervenors, and customers to review and test Hydro's costs for prudence and efficiency, and to understand how those costs are allocated across customer classes.

To allow for the commissioning of the Muskrat Falls project and the finalization of Government's rate mitigation plan, Hydro delayed its submission of a GRA in 2020 to ensure the appropriate and necessary information was available. The time period elapsed since Hydro's last GRA makes this proceeding an important opportunity for a comprehensive and transparent review of Hydro's costs and cost management practices. As a Crown corporation and regulated public utility, transparency and accountability are fundamental, and Hydro values engagement with the Board and intervenors through the GRA process.

1.2 The Application

The purpose of this application is to update the rates to be charged by Hydro for the supply of electricity, enable the review of costs and how they are allocated amongst customer classes, and allow an opportunity for Hydro to earn a just and reasonable return. This includes updating rates for the supply of electricity to Hydro's Utility customer, Newfoundland Power, and to Hydro's Industrial and Rural customers, as well as updating the rules and regulations applicable to service to all of Hydro's customers.

The evidence provided within Hydro’s application is structured as follows:

- Chapter 1: Overview. This chapter provides a high-level overview of the applicant, Hydro, the context for this application and the key components of Hydro’s proposals.
- Chapter 2: Managing Our Business. This chapter provides information on Hydro’s approach to safely and reliably serving customers throughout Newfoundland and Labrador, through regular customer engagement, sound business and *Good Utility Practice*,³ and a focus on cost management and continuous improvement. It also outlines forecast customer load requirements.
- Chapter 3: Regulated Operating Costs. This chapter outlines Hydro’s forecast operating costs for the 2027 Test Year as well as a discussion on changes versus (i) 2019 Test Year, Hydro’s last rate-setting year, and (ii) 2024, Hydro’s most recent audited year-end.⁴
- Chapter 4: Muskrat Falls Supply Costs. This chapter outlines Hydro’s supply costs related to energy and capacity from the Muskrat Falls Assets, which are now included in Hydro’s 2027 Test Year revenue requirement.
- Chapter 5: Revenue Requirement. This chapter provides Hydro’s 2027 Test Year revenue requirement, including supply costs, rate mitigation and return on rate base. It also outlines financial proposals relating to depreciation rates and methodology, and proposals related to Hydro’s regulatory deferrals, including Hydro’s proposed Long-Term Supply Cost Variance Deferral Account.
- Chapter 6: Rates and Regulations. This chapter provides Hydro’s proposed Cost of Service Study for the current application, the rate proposals to recover revenue requirement for the 2027 Test Year.

³ Hydro defines “*Good Utility Practice*” in the same manner as defined in the *Water Management Regulations* under the EPCA. *Good Utility Practice* means those practices, methods or acts, including but not limited to the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry in Canada, that at a particular time, in the exercise of reasonable judgment, and in light of the facts known at the time a decision is made, would be expected to accomplish the desired result in a manner which is consistent with laws and regulations and with due consideration for reliability, safety, environmental protection, and economic and efficient operations.

⁴ Audited results for 2025 are unavailable as of the time of preparation of the filing. Hydro will file an addendum to the 2026 GRA when Hydro’s 2025 results receive assent in the House of Assembly. Hydro’s 2025 results have been provided confidentially to the Board in Hydro’s 2025 Annual Return, which was filed on April 30, 2026.

1.3 About Hydro

Hydro's mandate includes:

- Engaging in the development, generation, production, transmission, distribution, delivery, supply, sale, export, purchase and use of power on an economic and efficient basis; and
- Supply of power, at rates consistent with sound financial administration, for domestic, commercial, industrial, or other uses in the province and subject to the prior approval of the Lieutenant-Governor in Council, outside of the province.⁵

Hydro is a utility as defined in the *Act*, and, as such, is subject to the provisions of the *Act* and regulation by the Board. Hydro is also subject to the *EPCA*, and its mandate is to execute and uphold provincial power policy, including, among other things, operating in a manner that results in power being delivered at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

In December 2024, the *Hydro Corporation Act, 2007*, was repealed and replaced by the *Hydro Corporation Act, 2024*, which served to finalize the amalgamation of Nalcor and Hydro effective January 1, 2025. As a result, all Nalcor subsidiaries are now Hydro subsidiaries and are part of Hydro's non-regulated operations. Hydro's proposals within this application pertain to costs associated with Hydro's regulated operations only.

While organizational changes have occurred, Hydro's priorities and legislative mandate have not changed. Safety remains Hydro's first priority. Hydro's framework for safety performance⁶ ensures its safety management system reflects *Good Utility Practice* or industry standards. Hydro experienced a workplace fatality in 2023—this incident is a tragic reminder of the hazards that exist in the electricity industry.

Hydro operates with a strong cost-conscious focus, achieving inflation-adjusted operating cost reductions since 2019, as shown in Chart 1-1. Hydro manages and controls its costs using the same disciplined approach regardless of whether those costs are classified as regulated or non-regulated.

⁵ *Hydro Corporation Act, 2024*, SNL 2024, c. H-18, s. 14.

⁶ Hydro's overall safety performance, including statistics and performance against Electricity Canada comparators, is reported to the Board on a quarterly basis in its Quarterly Regulatory Report. Please refer to Hydro's most recent report, "Quarterly Regulatory Report for the Quarter Ended December 31, 2025," Newfoundland and Labrador Hydro, February 17, 2026.

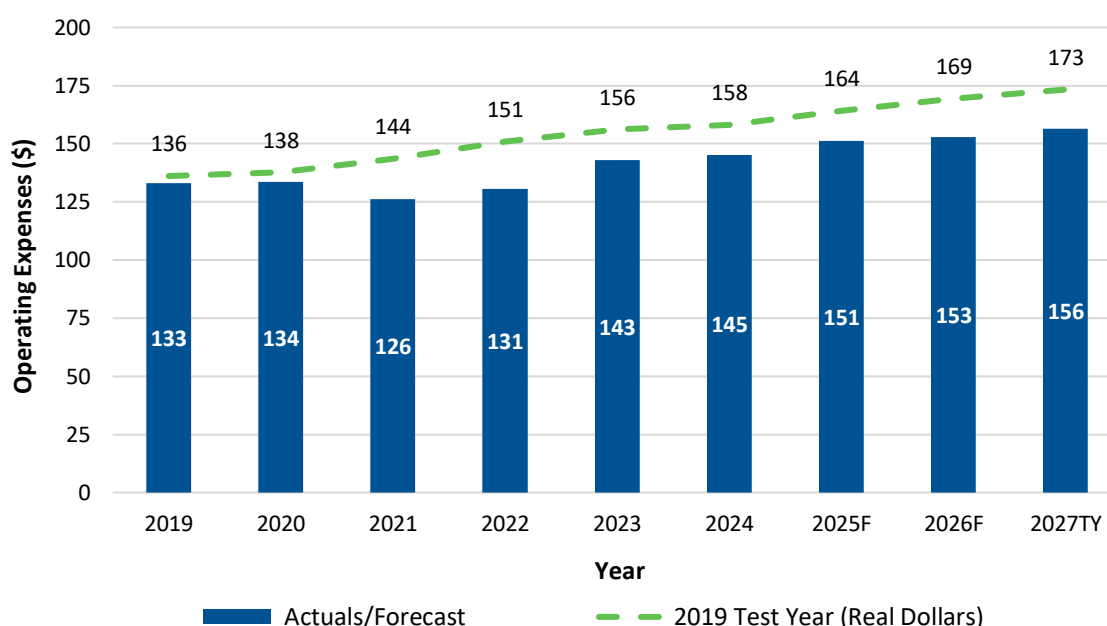


Chart 1-1: Operating Costs (\$ Millions)⁷

1 This focus on cost management supports the delivery of reliable, least-cost service to customers. Hydro
2 has included a commitment to further savings for customers in the 2027 Test Year through a self-
3 imposed productivity allowance as discussed in Chapter 2, Section 2.4.6.

4 **1.3.1 The Electricity System**

5 Hydro is the main generator and transmitter of electricity in the province. Hydro provides electricity,
6 either directly or through its Utility customer, Newfoundland Power, to all electricity customers in the
7 province. There are more than 300,000 customers⁸ in over 200 communities. In addition to its Utility
8 customer, Hydro has approximately 39,600 Rural customers located on the Island and in Labrador, six
9 Island Industrial customers and two Labrador Industrial customers.⁹

10 Hydro's distribution service areas are located throughout rural communities on the Island, including the
11 Great Northern Peninsula, along the South Coast, Fogo and Change Islands and White Bay—Baie Verte
12 area, and include most of the communities located in Labrador. Hydro's integrated transmission system

⁷ Throughout this chapter, Hydro's operating costs in 2025F, 2026F and 2027TY are shown net of deferred labour costs to the General Expenses Capitalized Deferral Account as approved in Board Order No. P.U. 32(2025).

⁸ Includes approximately 277,000 customers serviced by Hydro's Utility customer, Newfoundland Power.

⁹ Energy sales to the Labrador Industrial customers are non-regulated.

- 1 extends thousands of kilometres, linking generation facilities in Labrador with the island of
- 2 Newfoundland and with neighbouring systems via the Maritime Link. Hydro's system is shown in Figure
- 3 1-1.



Figure 1-1: Electricity System

1 The Island Interconnected System receives the majority of its electricity from Hydro’s hydroelectric
2 plants located outside the Avalon Peninsula or from the Muskrat Falls Hydroelectric Generating Facility
3 in Labrador, and serves customers dispersed across the island. The system is connected to the North
4 American Grid through Nova Scotia via the Maritime Link. Electricity is delivered to the Island
5 Interconnected System from generation sources through either the LIL or the bulk 230 kV transmission
6 system that runs from Stephenville to St. John’s. The remaining electricity is primarily sourced through
7 thermal generation and PPAs, including wind generation. Hydro also relies on CTs and diesel generating
8 units as critical resources for meeting peak demand, providing emergency backup, addressing localized
9 supply needs, transmission outage support, and supporting synchronous condensing requirements.
10 These units are typically dispatched only when electricity demand or reserve requirements cannot be
11 met by hydroelectric and thermal generation.

12 On the Labrador Interconnected System, Hydro supplies customers in Labrador East and Labrador West
13 with Recapture Energy and TwinCo Block Energy purchased from Churchill Falls.¹⁰ When Recapture
14 Energy can be exported for the benefit of customers, domestic electricity demand is instead met using
15 generation from Muskrat Falls.¹¹ This approach enables additional Recapture Energy exports to external
16 markets and maximizes the value of Hydro’s hydrological resources for customers. Hydro also relies on
17 the Happy Valley-Goose Bay GT, which is typically dispatched only when electricity demand or reserve
18 requirements cannot be met.

19 Hydro also supplies customers within Rural and Isolated systems on the Island and in Labrador. For
20 many of these communities, diesel generation remains the only source of electricity. Where possible,
21 Hydro utilizes energy from renewable PPAs to supply electricity to customers in isolated communities at
22 a lower cost than diesel generation while also reducing environmental impacts, in accordance with
23 Hydro’s mandate.

¹⁰ Churchill Falls is operated by CF(L)Co. The TwinCo Block is a firm 225 MW block of energy. The Recapture Energy is a firm 300 MW of energy; historically, this block of energy primarily serves Hydro’s load in Labrador, with the surplus energy being exported.

¹¹ As reported in Hydro’s Supply Cost Variance Deferral Account Monthly Reports, Muskrat Falls and Hydro entered into a PPA for the purchase and sale of residual block energy in February 2022. Under this Agreement, Labrador Interconnected, Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, may now be serviced with energy from the Muskrat Falls Hydroelectric Generating Facility. The price paid by Hydro does not change as a result; therefore, customers are kept whole.

Overall, Hydro operates its electricity system using the principle of economic dispatch, as further described in Chapter 2. This means Hydro schedules and controls its generating units so that electricity demand is met at the lowest possible cost while maintaining system reliability and respecting system constraints.

1.3.2 Hydro's Assets

Hydro is accountable for the management of the asset base necessary to service customers as follows:¹²

- **Generation**—Hydro has an installed generating capacity of over 2,658 MW,¹³ which includes 10 hydroelectric generating stations,¹⁴ 1 oil-fired plant, 4 CTs, and 24 diesel generating stations.¹⁵ Hydro completes ongoing forecasts of electricity requirements in the province and advances options to ensure adequate supply to reliably meet electricity demand.
- **Transmission and Distribution**—In addition to the 1,100 km 900 MW HVDC LIL, Hydro operates and maintains approximately 4,500 km of transmission lines and numerous high voltage terminal stations, which connect to the generation and delivery points for distribution systems to customers. Hydro also operates and maintains approximately 2,700 km of distribution lines.
- **System Operations**—Hydro operates and provides oversight of the bulk electricity system in Newfoundland and Labrador to reliably meet the changing requirements of electricity customers by utilizing the combination of available generation and power delivery resources to provide service safely, reliably, and cost-effectively.
- **Customer Service**—Customer service activities address the requirements of Newfoundland Power, Industrial customers, and Hydro's direct residential and commercial customers.

¹² Including the Muskrat Falls generation and transmission assets, which are owned by non-regulated subsidiaries.

¹³ Excluding Churchill Falls, which is operated by CF(L)Co, and the Menihek Hydroelectric Generating Station, which is operated by Hydro. Hydro purchases TwinCo Block and Recapture Energy from Churchill Falls to provide an electricity supply to the Labrador Interconnected System. All energy generated by the Menihek plant is sold to Hydro-Québec.

¹⁴ Including Exploits and Star Lake assets, which are owned by Government and operated by Hydro. All of the power generated at these facilities is sold to Hydro through a PPA.

¹⁵ Including Natuashish Diesel Generating Station, which is owned by Mushuau Innu First Nation and operated by Regulated Hydro on their behalf.

1 Figure 1-2 provides an overview of the assets on Hydro’s system.

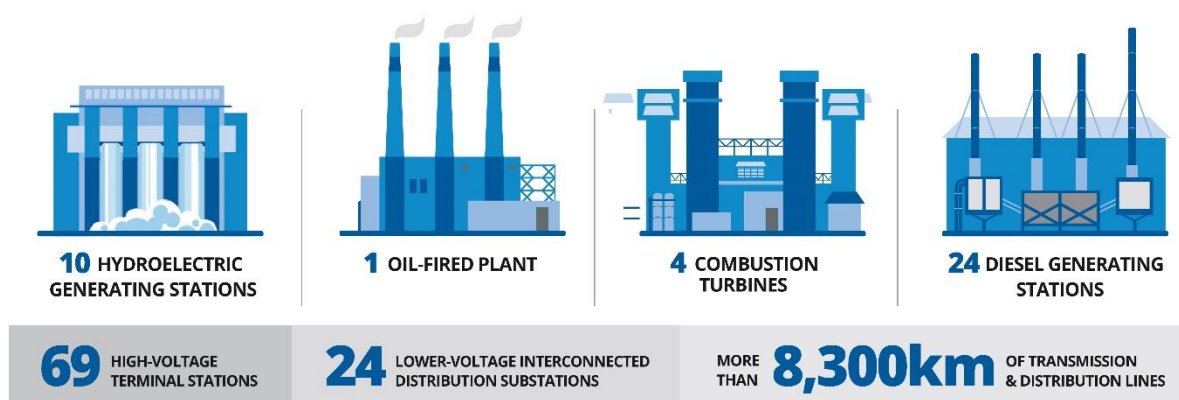


Figure 1-2: Hydro’s System Overview

2 The Muskrat Falls Hydroelectric Generating Facility, with a capacity of 824 MW, together with the rest of
3 the Muskrat Falls Assets, supplies power to the interconnected customers on the island of
4 Newfoundland. The Muskrat Falls Assets are a significant component of the province’s generation
5 portfolio and, while managed by Hydro, are exempt from the *Act*, regulation and oversight by the
6 Board.¹⁶ Hydro manages all areas of its operation to the same standard—applying an operational
7 philosophy of *Good Utility Practice* and in line with its mandate to provide least-cost, reliable service in
8 an environmentally responsible manner.

9 The Muskrat Falls Assets provide significant benefits to the people of Newfoundland and Labrador.
10 Hydro’s integration of the Muskrat Falls Assets into the provincial electricity system reduces reliance on
11 thermal generation, supports customer reliability, and, together with the Maritime Link,¹⁷ provides
12 increased access to import and export market opportunities as discussed in Section 2.2.2. This enables
13 Hydro to transact with neighbouring jurisdictions, optimizing the value of this renewable electricity and
14 resulting in electricity exports and imports for the benefit of customers.

15 The Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets were fully
16 commissioned in November 2021, and the LIL was commissioned in April 2023. Energy is delivered from

¹⁶ OC2013-343 and the Muskrat Falls Project Exemption Order expressly provide that all associated costs are fully recoverable through Island Interconnected System customer rates and are not subject to disallowance, reduction, or regulatory adjustment.

¹⁷ The Maritime Link, owned by Emera Inc., includes a set of subsea cables spanning the seabed of the Cabot Strait, connecting transmission systems in Newfoundland and Labrador with Nova Scotia. The Maritime Link enables the delivery of exports to the North American market, allows for imports to support Island Interconnected System reliability and reservoir optimization, when available, and has other system benefits, including reduced under-frequency load shedding.

1 Labrador to the Island Interconnected System through transmission lines in Labrador, across the Strait of
2 Belle Isle via subsea cable, over the 1,100 km LIL transmission line to the Soldiers Pond Converter
3 Station.

4 With the commissioning of the Muskrat Falls Assets, over 90% of the energy generated by Hydro for
5 usage in the province is renewable, making Hydro a national leader in renewable energy generation¹⁸
6 and enabling the province to meet its provincial and federal clean energy goals.¹⁹ From the optimal use
7 of Hydro’s renewable energy resources, Hydro was able to dramatically reduce the use of Holyrood TGS,
8 decreasing greenhouse gas emissions from electricity generation by 45% from 2019²⁰—a significant
9 accomplishment and step on the path to a net-zero electricity sector. Total greenhouse gas emissions by
10 Hydro since 2019 Test Year have reduced by 43% to the end of 2024, demonstrating Hydro’s
11 commitment to generating electricity in an environmentally responsible manner.

12 In the 2027 Test Year, forecast No. 6 fuel use at the Holyrood TGS is about one-third of the level forecast
13 for the 2019 Test Year. This represents a reduction of more than 1.0 million barrels of fuel and a
14 decrease in forecast production of over 600 GWh compared to the 2019 Test Year. As a result, No. 6 fuel
15 costs in the 2027 Test Year are \$129.7 million lower, largely due to the commissioning of the Muskrat
16 Falls Assets, which displaces generation at Holyrood. A fulsome discussion of Hydro’s fuel costs can be
17 found in Chapter 5, Section 5.2.1.

18 Hydro’s effective management and operation of provincial generating and transmission resources can
19 be measured by outcomes that include increased LIL deliveries for Island supply and increased exports
20 over the Maritime Link. Increased generation from Muskrat Falls supports load requirements on the
21 Island Interconnected System and enables Hydro to increase its exports over the Maritime Link to sell
22 power to external markets. The profits of these exports benefit customers by mitigating costs associated
23 with the Muskrat Falls Assets. Further information on the value for customers provided by exports is
24 included in Chapter 2, Section 2.2.2.

¹⁸ In 2023, approximately 66% of total generation in Canada came from renewable sources. Canada Energy Regulator, “Renewable Energy in Canada,” <https://rec-cer.gc.ca/en/data-analysis/energy-commodities/electricity/report/canadas-renewable-power/provinces/renewable-power-canada-canada.html>.

¹⁹ Natural Resources Canada, “Powering Canada’s Future: A Clean Electricity Strategy,” Government of Canada, <https://natural-resources.canada.ca/energy-sources/powering-canada-s-future-clean-electricity-strategy>.

²⁰ Hydro’s greenhouse gas emissions from Holyrood TGS were 593,469 tonnes in 2024. This is reduced from 1,081,535 tonnes in 2019.

1 Chart 1-2 provides the five-year actual LIL deliveries to the Island.

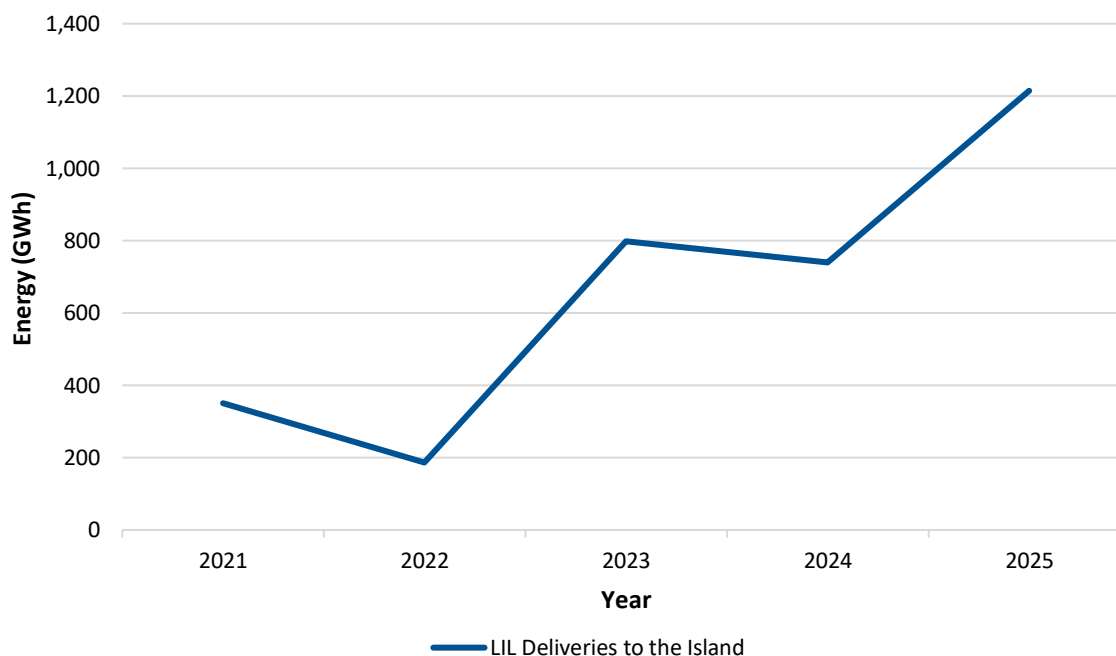


Chart 1-2: LIL Deliveries to the Island 2021–2025

2 1.3.3 Integration of Regulated and Non-Regulated Operations

3 In June 2021, Government announced the movement of Nalcor’s operations into Hydro. Initially, the
4 changes were operational in nature, and the companies began to operate as an integrated organization
5 in accordance with the direction of the province.²¹

6 A significant reorganization of the executive structure occurred in November 2021,²² with a sizable
7 reduction in the executive team from 18 positions down to 11, and a shift in organizational structure
8 focused on functional accountabilities rather than legal entities or regulatory oversight.²³ The new
9 structure focused on reducing duplication of effort by entity and drove a broader, unified focus on how
10 the business operates. The Nalcor legal entity remained unchanged until January 1, 2025, when the

²¹ Government of Newfoundland and Labrador, “Premier Furey and Minister Parsons Announce Nalcor Operations Moving Under Newfoundland and Labrador Hydro,” June 23, 2021, <https://www.gov.nl.ca/releases/2021/exec/0623n04/>.

²² Newfoundland and Labrador Hydro, “Newfoundland and Labrador Hydro Streamlines Executive Structure To Reduce Costs And Focus On Better Serving The Province,” November 2, 2021, <https://nlhydro.com/newfoundland-and-labrador-hydro-streamlines-executive-structure-to-reduce-costs-and-focus-on-better-serving-the-province/>.

²³ For further information, please refer to “Organizational Structure Announcements – Additional Information,” Newfoundland and Labrador Hydro, December 7, 2021.

- 1 *Hydro Corporation Act, 2024*, finalized the legal amalgamation of Nalcor and Hydro. The amalgamation
- 2 formalized the new operating structure that had been in place since 2021.
- 3 Hydro’s executive team and their associated accountabilities continue to evolve with organizational needs.
- 4 As a unified organization, Hydro operates its business with both regulated and non-regulated aspects.
- 5 Both align with Hydro’s mandate, and the structure is based on a functional organization design.
- 6 Employees with similar expertise are grouped together under a functional leader. The functional areas of
- 7 accountability by executive team member as of April 1, 2026, are provided within Exhibit 1.
- 8 Hydro’s corporate structure post-amalgamation is shown in Figure 1-3.

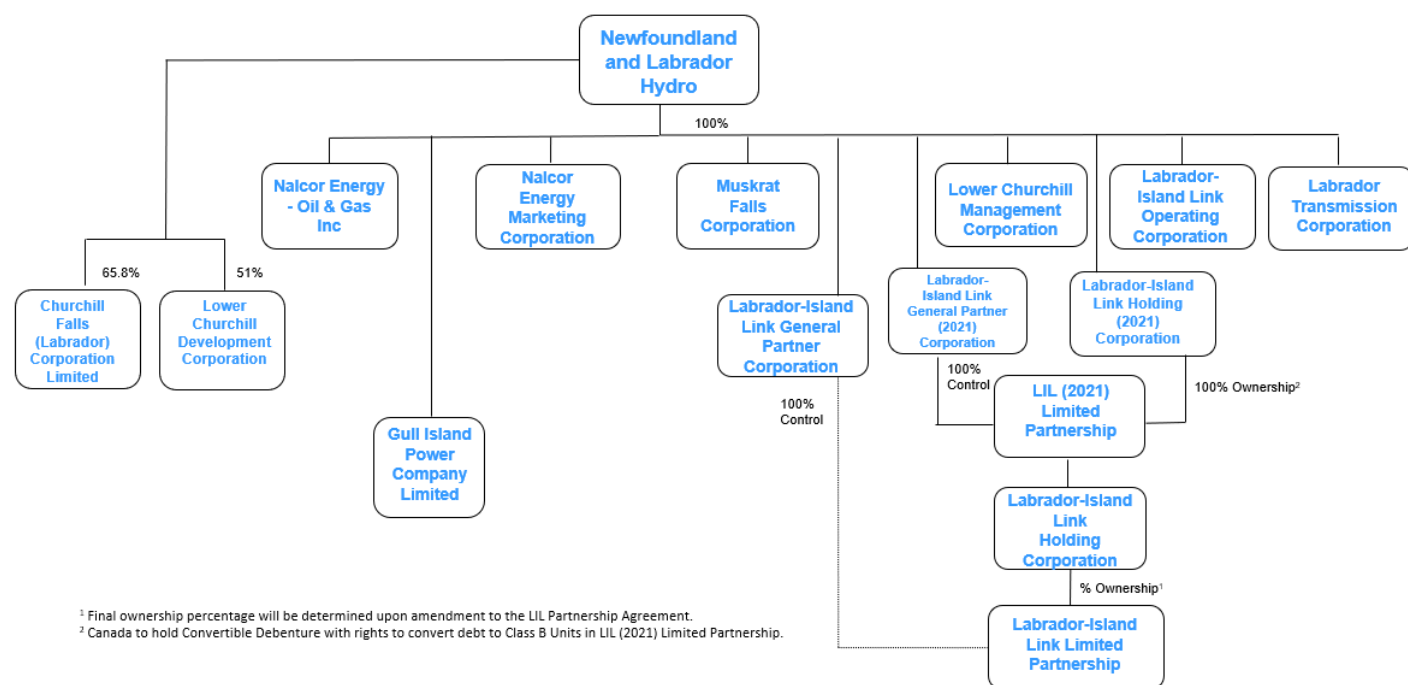


Figure 1-3: Corporate Structure Effective January 1, 2025²⁴

- 9 As outlined in Hydro’s Report on Amalgamation Activities,²⁵ upon legal amalgamation effective
- 10 January 1, 2025, the regulatory and organizational changes were minimal. The organizations that were
- 11 subsidiaries of Nalcor are now subsidiaries of Hydro. There were no transfers of FTEs from the non-
- 12 regulated business segment to the regulated business segment; and while Hydro is subject to the Act as

²⁴ The corporate structure remains the same at the time of submission of this application. The legal names of the subsidiaries were not changed as a result of the amalgamation.

²⁵ “Report on Amalgamation Activities,” Newfoundland and Labrador Hydro, rev. April 17, 2025 (originally filed April 15, 2025).

a regulated utility, the majority of the assets previously held by Nalcor and related activities, including future sustaining capital expenditures, will continue to be exempt from the *Act* as a result of Orders made by the Lieutenant-Governor in Council.²⁶ There were no operational changes in relation to these exempted assets, with the exception of assets and related activities associated with Information Systems.²⁷

The *Hydro Corporation Act, 2024*, had no impact on any of the subsidiary companies, as shown in Figure 1-3, including those which hold the Muskrat Falls Assets: Muskrat Falls Corporation, Labrador-Island Link Limited Partnership, and Labrador Transmission Corporation. These companies continue to exist as they had as subsidiaries of Nalcor with their own Boards of Directors. In accordance with Government direction, their associated assets and activities are not subject to the *Act* and are considered part of Hydro's non-regulated operations.

Hydro manages and isolates the costs of its regulated and non-regulated operations to ensure that customers ultimately pay only the cost associated with providing them the regulated service as part of Hydro's recovery through customer rates. Costs incurred are allocated in accordance with the Intercompany Guidelines, consistent with practices in place prior to amalgamation. The Intercompany Guidelines were updated in 2026 and are provided within Exhibit 2.

It is Hydro's duty to make responsible, evidence-based decisions for all its operations, whether regulated or non-regulated, to ensure it is responsive to the needs of its customers and the transformation occurring within the energy industry.

1.4 Transition of the Electricity Industry

The energy sector is evolving. Technological innovation, such as the advancement of Artificial Intelligence, and public policy around the impacts of climate change, are driving capital investment. Increased demand arising from broad electrification is leading to industry supply chain risks, including demand-induced scarcity, upward pressure on prices and long lead times. After decades of nearly flat electricity demand growth, electricity consumption in Canada is accelerating rapidly. Electricity Canada

²⁶ Please refer to OC2024-217.

²⁷ As discussed in Hydro's Report on Amalgamation Activities, Information Systems assets and related activities are not exempt from the *Act*. Therefore, any capital expenditures related to Information System assets post-amalgamation are subject to review and approval by the Board. The recovery of related costs from customers also continues to be subject to regulatory approval.

estimates that by 2050, the grid is expected to double or triple in size, from 600 TWh/year to over 1,200 TWh/year due to increased demand from all sectors of the economy. Additionally, data centre growth supporting Artificial Intelligence will further increase the demand on the power grid.²⁸

In addition, efforts by federal and provincial governments to balance carbon management and electrification and enable participation in the clean energy transition provide opportunities for and have impacts on Hydro's operations. Whether it is the electrification of public facilities, the transportation sector, or increased wind energy integration, as the province's Crown utility, Hydro has a role in informing and enabling such public policy developments and associated industries.

As a Crown utility, Hydro implements provincial energy policy and is responsible for pursuing additional capacity to meet the increasing demand for electricity within the province, as required. Hydro is also focused on displacing fossil fuel consumption with renewable sources of energy on its Interconnected and Isolated systems, where practical.

Broad electrification initiatives in the country and beyond have placed increased pressure not only on the labour market but also on supply chains and material costs. Market pressures drive increased costs for Hydro in both capital investments and operating costs alike, limiting Hydro's ability to find opportunities to reduce costs for customers without introducing operational risk.

System investments impact customers' rates; the reliable supply of electricity and the cost of electricity are key concerns for customers. Hydro remains committed to engaging with customers to gain their input on priorities, balancing cost and reliability, with a focus on minimizing investment where practical, and making prudent, transparent decisions that are in the best interest of the people of the province.

1.5 Engaging Our Customers

Hydro is committed to engaging the people it serves and helping customers understand both the work it does and its responsibility to provide reliable, least-cost service in an environmentally responsible manner. Beyond regular customer surveys, Hydro connects with customers and stakeholders through

²⁸ "Artificial Intelligence – Electricity Canada's submission to the Standing Committee on Science and Research (SRSR)," Electricity Canada, December 2025, p. 2, <https://www.electricity.ca/files/ElectricityCanada-e-1.pdf>.

- 1 multiple forums, obtaining their perspective on electricity service reliability, capital investment levels
2 and provincial electricity rates.
- 3 Hydro regularly surveys its direct customers. Hydro’s overall customer service satisfaction scores have
4 remained strong and consistent for the last decade, as noted for residential customers in Chart 1-3, in
5 comparison to the Electricity Canada 2023 National Customer Survey average of 72%.²⁹

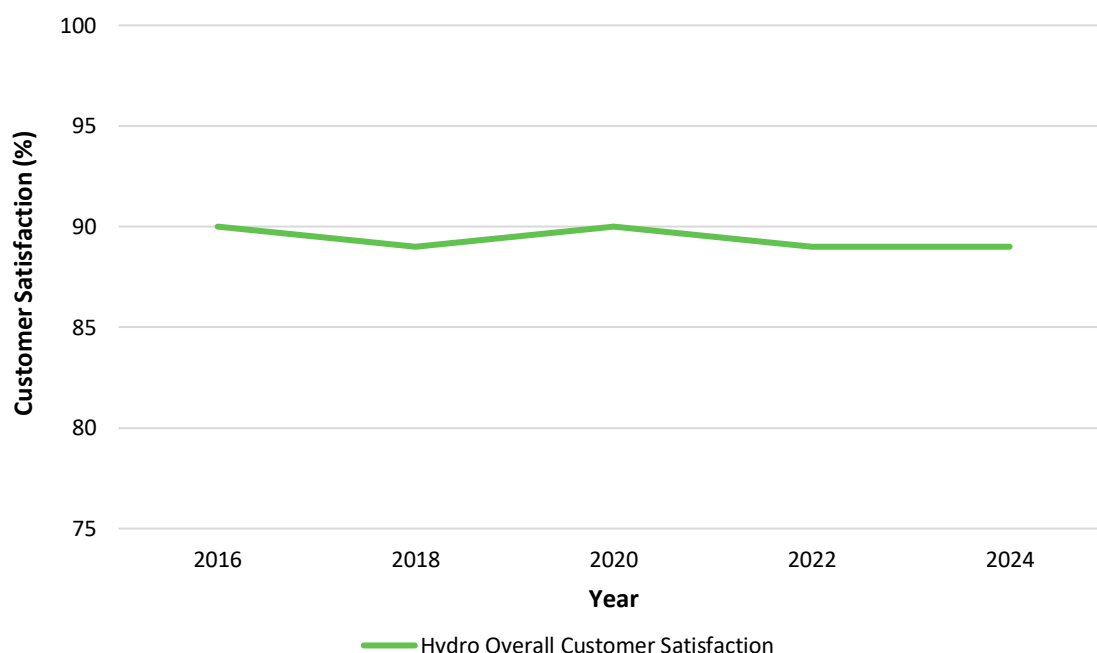


Chart 1-3: Hydro’s Residential Overall Customer Satisfaction Index 2016 to 2024

- 6 In January 2024, Hydro completed a digital public engagement survey for all electricity customers in the
7 province, not only Hydro’s customers. The engagement contained questions relating to reliability, cost,
8 investment, growth, clean energy, and options for new sources of electricity. The online survey was
9 administered by a third-party research partner, and more than 2,000 responses were received. Key
10 findings from the survey indicate that respondents:
- 11 • Are concerned about the rising cost of living, including electricity rates;
 - 12 • Prioritize lower electricity rates over improvements in reliability or clean energy; and

²⁹ Electricity Canada, “Understanding members’ customers with Diana Dominique,” February 5, 2024,
<https://www.electricity.ca/knowledge-centre/journal/understanding-members-customers-with-diana-dominique/>.

- Recognize that the province has a reliable electricity system that is supplied largely from renewable sources.

Within the survey, customers were asked to provide their priorities for the delivery of electricity service in the province. Respondents were asked to allocate 100 points across three categories in order of importance: (i) lowest impact on rates, (ii) most reliable, and (iii) cleanest energy supply. As shown in Figure 1-4, customers identified lower electricity rates as their highest priority.

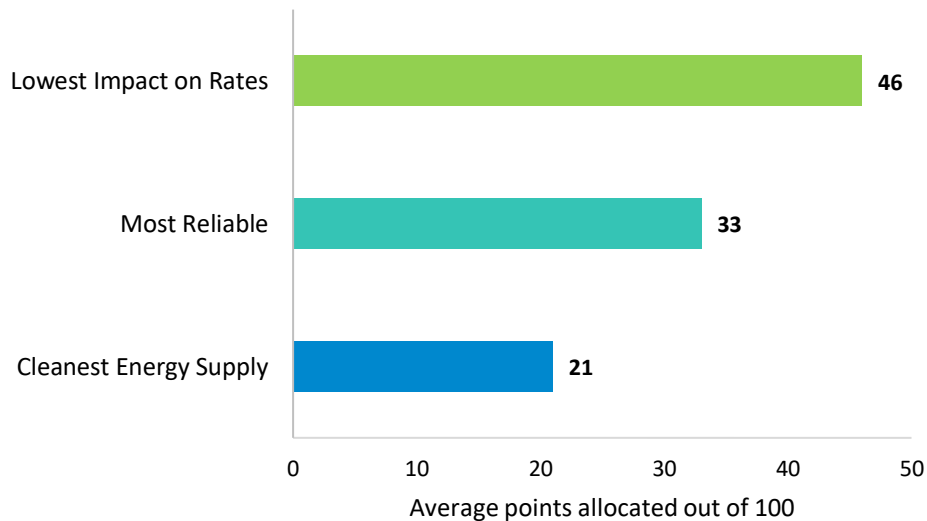


Figure 1-4: Customer Priorities³⁰

Hydro's decisions impact customers; as such, Hydro uses customer engagement to help inform many facets of its business, including its capital investment strategy, compilation of operating budgets and system planning. Hydro believes it is generally understood that reliability is correlated with the cost to provide service. A majority of customers have indicated that they are satisfied with current reliability levels, and have been clear that they do not wish to pay more for increased reliability. The relationship between cost and reliability has also been noted and confirmed in academic research; for example, a study completed by the University of Saskatchewan concluded that:

It is neither practically realizable nor economically justifiable to attempt to create an absolutely reliable power system. [...] It is evident therefore that reliability and economic

³⁰ Question asked: Please tell us what's most important to you by assigning a value to each factor. You have 100 points to share between all three factors. The more points you give to a factor, the higher the importance you give to it.

constraints can compete, and can lead to difficult managerial decisions at both the planning and operating phases.³¹

Like other utilities across the country, Hydro works to balance costs with maintaining the expected level of system reliability. Hydro focuses on cost management as a means through which to mitigate rate impacts on its customers.

1.6 Rate Mitigation

In 2024, Government outlined its final rate mitigation plan, which limits electricity rate impacts on Island Interconnected customers for all of Hydro's costs up to and including 2030. Hydro's report on the implementation of the rate mitigation plan, filed with the Board in October 2024, is provided as Exhibit 3.

Government has directed Hydro to structure future rate applications such that retail electricity rate increases attributable to Hydro's costs are targeted at 2.25% annually for Domestic customers on the Island Interconnected System through 2030, with rates structured for other customers on the Island Interconnected System in a manner that is compatible with this target rate increase.³² These directions effectively cap the recovery of Hydro's costs through customer rates and shift a significant portion of costs away from ratepayers.

The rate mitigation plan is supported by substantial federal and provincial financing measures, including federal investment in the LIL in the form of a convertible debenture, an additional federal loan guarantee, and the capital restructuring of the Muskrat Falls Corporation and Labrador Transmission Corporation. These measures lower the cost of financing and provide additional sources of funding to support rate mitigation. Any remaining funding required to achieve the targeted rate increases is to be provided by Hydro, to the extent possible, through its own sources. This will be accomplished through applying a portion of Hydro's earnings against balances owing from Island Interconnected System customers. Hydro achieves these earnings through the business activities of its subsidiaries, including Nalcor Energy Marketing and Nalcor Energy - Oil and Gas Inc. The average annual rate mitigation

³¹ Peng Wang, "Reliability Cost/Worth Considerations in Distribution System Evaluation," University of Saskatchewan, 1998, sec. 8, p. 180. https://www.collectionscanada.gc.ca/obj/s4/f2/dsk1/tape8/PQDD_0016/NQ37921.pdf.

³² Such as Island Industrial Customers.

- 1 funding required from Hydro’s internal sources³³ is estimated to be upwards of \$350 million per year.³⁴
- 2 Operating as a single, unified organization supports this approach by ensuring that decisions across all
- 3 lines of business, regulated and non-regulated, are aligned toward a common objective of benefiting
- 4 customers and supporting rate stability.
- 5 Figure 1-5 outlines the sources of rate mitigation funding.

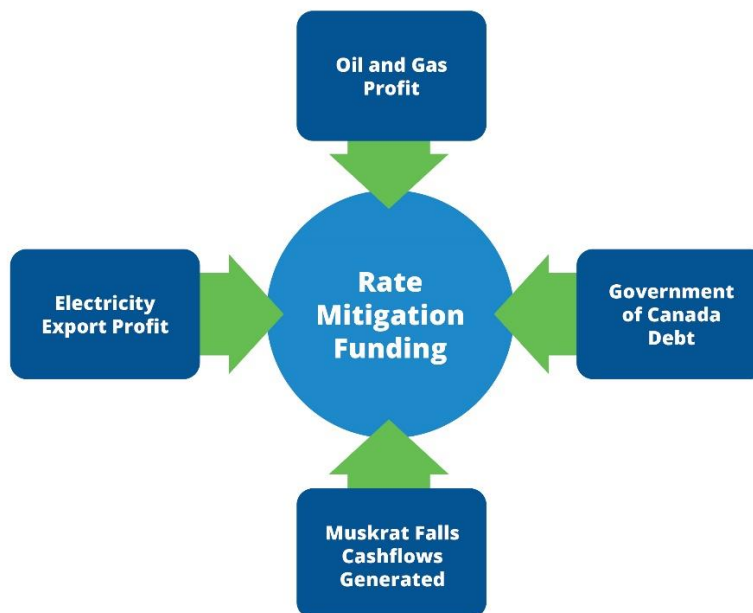


Figure 1-5: Sources of Rate Mitigation Funding³⁵

- 6 Government’s rate mitigation plan has been incorporated into Hydro’s 2027 Test Year and reflects the
- 7 funding required to offset the portion of Hydro’s costs that are not expected to be recovered through
- 8 customer rates. Hydro’s 2026 GRA includes approximately \$502 million in rate mitigation funding
- 9 required in 2027. Variances from the test year forecast will continue to be deferred as part of Hydro’s
- 10 Supply Cost Variance Deferral Account framework.
- 11 Through a combination of federal financing support, provincial policy direction, Hydro-sourced funding,
- 12 and regulatory mechanisms, the rate mitigation plan provides rate stability for customers through 2030
- 13 while maintaining transparency and accountability in the treatment of Muskrat Falls supply costs.

³³ Excluding Government of Canada Convertible Debenture.

³⁴ Annual rate mitigation funding requirements are shown in Chapter 5, Table 5-6. The estimated average is calculated using 2024 Actuals, 2025 and 2026 Forecast, and 2027 Test Year for Hydro’s internal sources.

³⁵ Government of Canada Debt is in the form of a convertible debenture.

1.7 2026 General Rate Application Proposals

Hydro operates in line with its statutory obligation to provide customers with safe, reliable, environmentally responsible service at the lowest possible cost. Since its last GRA, Hydro has:

- Prudently managed its operating costs—the 2027 Test Year forecast is approximately 10%³⁶ or \$17 million below the 2019 Test Year forecast in real dollars;
- Commissioned the Muskrat Falls Assets and integrated them into the provincial electricity grid, with reliability steadily improving over time;
- Maintained strong customer satisfaction; and
- Focused investment on renewal of aging assets and planned for required asset growth to meet customer demand and ensure ongoing system reliability.

1.7.1 2027 Test Year Revenue Requirements

Hydro's proposed revenue requirement³⁷ for the 2027 Test Year is approximately \$798 million, with a range of return on rate base of between 4.68% to 5.08%.

Hydro's revenue requirement is the sum of the return on rate base and other reasonable costs, which include operating costs, Muskrat Falls supply costs, fuel costs, power purchases, and depreciation. The revenue requirement also includes \$502 million in rate mitigation to offset total costs in accordance with Government's rate mitigation plan. A fulsome discussion of Hydro's revenue requirement is found in Chapter 5. Chart 1-4 shows the changes in Hydro's revenue requirement between the 2019 Test Year and the 2027 Test Year, broken down by component.

³⁶ 2019 Test Year in Real Dollars (\$173.3) - 2027 Test Year in Nominal Dollars (\$156.4) / 2019 Test Year in Real Dollars (\$173.3) = 9.8%. Please refer to Chapter 2 for the discussion on inflationary impacts and drivers of variances between test year forecasts.

³⁷ Hydro's proposed revenue requirement is net of rate mitigation. Unless otherwise stated, revenue requirement figures presented in this application are net of rate mitigation.

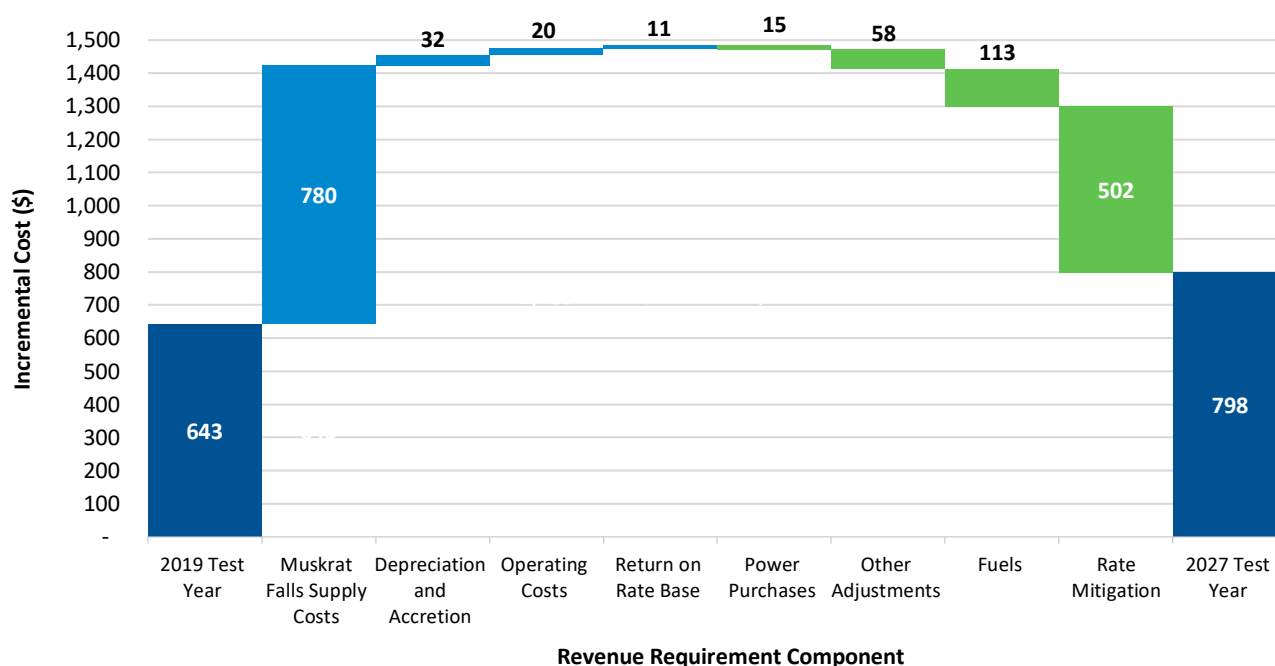


Chart 1-4: Hydro's Incremental Revenue Requirement (\$ Millions)

Hydro's 2027 Test Year revenue requirement has increased by approximately \$155 million when compared to the 2019 Test Year. The increase in revenue requirement since 2019 is primarily a result of Muskrat Falls supply costs, which are partially offset by rate mitigation and a decrease in fuel used at the Holyrood TGS.

1.7.2 Customer Rate Impacts

Hydro's final rates, which are compliant with Government's rate mitigation plan, where applicable, as outlined in Table 1-1, are proposed effective July 1, 2027.

Due to the passage of time between Hydro's GRAs, customers on the Labrador Interconnected System have not had any rate increase since 2019. Also during this time, there have been system additions and increases in operating costs that have increased the underlying cost of providing service beyond what is reflected in current rates. The calculation of the cost of service for Labrador Interconnected System Domestic and General Service customers indicated an estimated rate increase of approximately 8.5%. To mitigate the impact on customers, with support from Government, Hydro is proposing to smooth the required rate increase over a four-year period, beginning with a 2.25% annual rate increase proposed to take effect on July 1, 2027. This increase is consistent with Domestic and General Service Island Interconnected System rates effective July 1, 2027.

Hydro’s 2026 GRA proposes to make the 2027 Test Year base rates equivalent to July 1, 2026 rates for Newfoundland Power. The proposed 3.3% increase effective July 1, 2027 to Hydro’s Utility rate charged to Newfoundland Power is applied at the wholesale level, inclusive of the Project Cost Recovery Rider.³⁸ When this increase is flowed through Newfoundland Power’s customer rates, the resulting impact on the average domestic retail customer is an overall electricity rate increase of approximately 2.25%, consistent with Government’s rate mitigation plan.

Hydro is proposing a decrease in rates as of July 1, 2027 in comparison to July 1, 2026 rates for Island Industrial customers of 14.3%.³⁹ The rate decrease reflects the 2027 Cost of Service Study revenue requirement of \$42.8 million and utilization of the Project Cost Recovery Rider on July 1, 2027 to target the annual rate increase.⁴⁰ Please refer to Chapter 6 for further information.

The total rate impact of Hydro’s 2026 GRA and the July 1, 2027 rate applications by customer class are provided in Table 1-1.

Table 1-1: Estimated July 1, 2027 Rates Increases by Customer Class (%)⁴¹

Customer Class	Estimated July 1, 2027 Rate Change Relative to 2026 Rates⁴²
Utility ⁴³	3.3
Island Industrial ⁴⁴	(14.3)
Rural Labrador Interconnected ⁴⁵	2.25

³⁸ Adjustments to the Project Cost Recovery Rider for July 1, 2027 will be proposed in Hydro's July 1, 2027 Utility Rate Adjustment Application to be filed in 2027. Forecast and actuals may differ.

³⁹ Inclusive of the Project Cost Recovery Rider.

⁴⁰ Adjustments to the Project Cost Recovery Rider for July 1, 2027 will be proposed in Hydro's application for approval of the Island Industrial Customer Rate Adjustments effective July 1, 2027 to be filed in 2027. Forecast and actuals may differ.

⁴¹ Hydro's Rural customer rates, with the exception of Labrador Interconnected customers, are linked to those for Newfoundland Power customers through Government direction; accordingly, there are no rate proposals for those Rural customers contained within Hydro's 2026 GRA.

⁴² Rate for Hydro’s Utility and Island Industrial customers are reflective of Hydro’s estimated Project Cost Recovery Rider effective July 1, 2027. There is no increase to the Project Cost Recovery Rider as of July 1, 2027 being proposed within Hydro's 2026 GRA.

⁴³ The Utility rate increase reflects the wholesale rate increase effective July 1, 2027, which will result in an estimated 2.25% increase for end customers of Newfoundland Power in line with Government’s rate mitigation plan.

⁴⁴ Government has directed Hydro to structure future rate applications such that retail electricity rate increases attributable to Hydro’s costs are targeted at 2.25% annually for Domestic customers on the Island Interconnected System through 2030, with rates structured for other customers on the Island Interconnected System in a manner that is compatible with this target rate increase.

⁴⁵ Labrador Interconnected System rates reflect the rate smoothing of 2.25% per year for four years.

In the 2026 GRA, Hydro is also proposing to increase the Labrador Industrial Transmission Demand rate from \$1.08 per kW per month to \$2.00 per kW per month. The Government Diesel rate is proposed to increase by approximately 13%.

1.7.3 Other Proposals

Since its last GRA, Hydro has received Board direction on various items for inclusion within this GRA. In the interest of regulatory efficiency and to streamline the process for this application, Hydro submitted the following reports and applications in advance of the GRA to bring resolution to various issues and items wherever possible:

- Implementation of the Rate Mitigation Plan;
- Wholesale Utility Rate Adjustment;⁴⁶
- Disposition of Balances within the Hydraulic Resources Optimization Deferral Account;⁴⁷
- Cost of Service Methodology;⁴⁸
- Capitalization of General Expenses Deferral Account;⁴⁹
- Approval of an Accounting Deviation for Rate Mitigation Funding;⁵⁰
- Update to Intercompany Transactions Costing Guidelines;⁵¹ and
- Application for Recovery of Costs Associated with Information Systems Assets.⁵²

The resolution of these items has and will contribute to regulatory efficiency by reducing the breadth and complexity of this application. The remaining proposals detailed within Hydro's application include:

- 1) Proposals related to Hydro's capital structure and expenditures as detailed in Chapter 5.**

⁴⁶ Approved in Board Order No. P.U. 1(2025).

⁴⁷ Approved in Board Order No. P.U. 21(2025).

⁴⁸ Hydro's Cost of Service Methodology Application was filed to address key items prior to the GRA in relation to: (i) rate mitigation funding; (ii) transmission tariff revenue; (iii) greenhouse gas credits revenue; and (iv) the treatment of the Holyrood TGS after commissioning of the Muskrat Falls Project. The Application also included outstanding reports from the 2018 Cost of Service Methodology Settlement Agreement. For further information, please refer to "Application for Approval of Modifications to the Cost of Service Methodology," Newfoundland and Labrador Hydro, August 22, 2025.

⁴⁹ Approved in Board Order No. P.U. 32(2025).

⁵⁰ Approved in Board Order No. P.U. 34(2025).

⁵¹ "Intercompany Transaction Costing Guidelines – 2026 Update," Newfoundland and Labrador Hydro, March 30, 2026. Provided in "Review of Newfoundland and Labrador Hydro's Intercompany Transactions Costing Guidelines," Newfoundland and Labrador Hydro, March 30, 2026, att. 1.

⁵² "Recovery of Costs Associated with Information Systems Assets," Newfoundland and Labrador Hydro, April 1, 2026.

- 2) Disposition and/or amortization of the balances within Hydro’s existing deferral accounts as detailed in Chapter 5.
- 3) Proposals related to the creation of new deferral accounts and their respective disposition, as included in Chapters 5 and 6.
- 4) Cost of Service Methodology Proposals as detailed in Chapter 6.
- 5) Rate design changes for select customer classes as detailed in Chapter 6.

1.8 Summary

Hydro’s 2026 GRA reflects the organization’s commitment to delivering safe, least-cost, reliable, and environmentally responsible electricity service to customers in Newfoundland and Labrador. With the integration of the Muskrat Falls Assets, the provincial system has transitioned to one of the cleanest electricity grids in Canada, providing increased reliability and substantial renewable capacity. While rate mitigation currently manages the impact of Hydro’s overall costs on Island Interconnected System customers, Hydro’s costs directly influence customer rates on all systems. Accordingly, Hydro remains focused on disciplined cost management to help limit those impacts.

Since its last GRA, Hydro has maintained a strong focus on cost discipline and has prudently managed its operating expenses. On an inflation-adjusted basis, 2027 Test Year operating costs are forecast to be approximately \$17 million lower than the 2019 Test Year.

The rate proposals, revenue requirement, and supporting mechanisms included in this GRA are consistent with Hydro’s mandate while ensuring rate stability for customers.

Chapter 2

Managing Our Business



Chapter 2: Managing Our Business

Hydro’s utility and business practices result in the delivery of reliable, least-cost and environmentally responsible service to customers. Hydro’s focus on cost management has resulted in operating cost reductions in real terms since 2019, including lower labour and non-labour costs. Hydro is committed to further savings for customers in the 2027 Test Year and to continuously improve business processes and the delivery of electricity service.

As the electricity industry evolves, Hydro is managing rapid change and making investment decisions which have direct implications on reliable electricity supply and customer rates. To help inform its decision-making, Hydro regularly engages its customers and stakeholders and operates transparently within the regulatory framework.

This chapter of evidence outlines how Hydro manages its business in the best interests of customers.

2.1 Serving our Customers

Hydro is focused on providing safe, reliable electricity service while engaging customers and stakeholders in a transparent and meaningful way. Under the *EPCA*, Hydro is required to ensure customers have equitable access to an adequate, reliable, environmentally responsible electricity supply at the lowest possible cost. This includes planning for sufficient generation, transmission, and distribution capacity; operating the system in accordance with *Good Utility Practice*; and managing costs prudently to limit impacts on customer rates.

To support these obligations, Hydro develops a Reference Case forecast of firm electricity demand and energy requirements, reflecting customer, demographic, and economic factors. The load forecast informs key decisions, including GRA applications, evaluation of supply options and policy impacts, and system adequacy and reliability planning.

System reliability is achieved through a combination of operations and maintenance activities and ongoing capital investment. Hydro invests prudently to maintain and upgrade assets in a manner consistent with customer needs and expectations.

Hydro also places a strong emphasis on customer and stakeholder engagement. Customers can interact with Hydro through multiple channels, including social media, toll-free telephone service, email, and the

myNLhydro mobile and web platforms. Engagement through these channels has increased since the last GRA, particularly through myNLhydro and social media.

Hydro believes that informed and engaged customers are essential to effective system planning and service delivery. In addition to the day-to-day service delivery, Hydro regularly gathers customer feedback on reliability, outages, billing, and customer support. This input informs service improvements, asset management, and long-term capital planning. Engagement has also expanded to include broader input on system reliability, investment levels, and rates, including dedicated support for Industrial customers through a Key Accounts Specialist.

Hydro further supports engagement through its Electricity Feedback Panel, established in 2019, which is comprised of approximately 1,000 voluntary participants across the province. The panel provides input on a wide range of electricity-related topics through online surveys, helping Hydro better understand customer perspectives and priorities.

2.1.1 Customer Satisfaction and Feedback Results

Hydro measures customer service performance through a combination of transactional and relationship-based surveys, as well as spot engagement surveys.

Transactional surveys are conducted monthly with Residential and General Service customers who have recently contacted Hydro's call centre regarding billing, payments, new service, or power outages. These surveys measure overall satisfaction and first-call resolution, providing insight into customer experience during specific interactions. Since their introduction in 2017, transactional survey results have remained stable, with consistently strong satisfaction and issue resolution outcomes. Figure 2-1 shows average customer satisfaction rates in relation to Hydro's transactional survey results from 2019 through 2025.



Figure 2-1: Average Customer Transactional Survey Results 2019–2025

Hydro also conducts biennial Residential and General Service customer satisfaction surveys.¹ In the 2024 residential survey, 89% of respondents rated their overall satisfaction with Hydro at 7 or higher out of 10.² Residential satisfaction has remained consistent between 89% and 90% over the past decade, demonstrating sustained performance. Among General Service customers, overall satisfaction has exceeded 80% since 2017. The 2025 General Service Survey recorded satisfaction of 81%,³ a decrease from 2023, which was driven largely by results from the Northern region.⁴

As discussed in Chapter 1, customer feedback indicates that reliability is important to customers, but that affordability remains a higher priority. Hydro's engagement initiatives confirm that customers generally prefer stable or lower electricity rates over incremental improvements in reliability that would require additional capital investment. Hydro remains mindful of this perspective as it manages its infrastructure and applies asset management practices to support prudent investment while maintaining reliability, safety, and environmental performance.

This balance is reflected in the results of Hydro's 2024 digital engagement process, which sought customer input on the cost and reliability of the provincial electricity system. Four out of five respondents, or 80%, as shown in Figure 2-2 indicated that they believe the electricity system is highly reliable. 87% of respondents stated that they do not wish to pay higher rates to achieve fewer or shorter outages.

¹ The biennial General Service customer satisfaction surveys are conducted in alternating years with the Residential customer service surveys.

² Customers reported that they were somewhat satisfied (i.e., score of 7 or 8) and very satisfied (i.e., score of 9 or 10) on a 10-point scale, with 1 being 'not at all satisfied' and 10 being 'very satisfied.'

³ Scale is the same scale that is utilized in Residential customer survey. The proportion of respondents who rated *very satisfied* trended down in the Northern region versus the 2023 results. Given the relatively small sample size, this had an overall impact on the rating. Ratings of *very satisfied* increased in the Labrador region and remained unchanged from 2023 among respondents living in the Central region.

⁴ For further information about how Hydro is responding to customer concerns, please refer to "Electrical Service Provided to the Great Northern Peninsula – Inquiry by the Great Northern Chamber of Commerce – Hydro's Reply," Newfoundland and Labrador Hydro, March 31, 2026.



Figure 2-2: Reliability Score 2024 Engagement Survey

Customer preferences from Hydro’s most recent Electricity Panel in February 2026 demonstrate similar themes. The survey sought customer feedback on Hydro’s response to the Bay d’Espoir frazil ice extreme weather events and the degree to which customers wished to invest to strengthen the system to withstand the impacts of such events. Survey results indicated that Hydro’s handling of the energy conservation effort and its communications during the period are well-regarded, both receiving an average rating of 7.7 out of 10.

Consistent with other customer surveys on system reliability, the majority of respondents agreed that they are comfortable with the power system’s current level of reliability and thus prefer a cautious approach with respect to additional investment.⁵

Taken together with Hydro’s customer satisfaction metrics and overall reliability performance, these results indicate that Hydro’s current approach to system maintenance, reliability management, and capital planning is reasonable and aligned with customer expectations.

2.1.2 Reliability

Reliability of service is a fundamental component of Hydro’s mandate and a core expectation of customers across the province. Hydro operates as a vertically integrated electric utility, managing reliability across

⁵ The question posed to panelists was as follows: *We have been seeing more frequent and severe weather events, which are expected to increase due to the impacts of climate change. Some utilities choose to make additional investments to strengthen the electricity system against these extreme risks, while others do not. Investments to improve reliability can impact the rates customers pay. To help us understand customer expectations, please indicate the extent to which you agree or disagree with the following statements:*

(a) *I am comfortable with our power system’s current level of reliability, so I would prefer that additional investment be made cautiously.*

(b) *Hydro should invest more to reduce the impact of outages during extreme events.*

1 generation, transmission, and distribution assets while balancing customer preferences for affordability
2 and prudent investment.

3 Hydro measure's reliability performance using established industry metrics. Hydro's generation reliability
4 metrics are generally comparable to or better than equivalent industry metrics. Within transmission and
5 distribution operations, Hydro's performance against industry comparators is generally below average,
6 largely influenced by Hydro's geographically dispersed service territory and small customer population in
7 relation to comparators.

8 ***Distribution Reliability***

9 Hydro measures distribution reliability for both consumers supplied directly by Hydro-owned distribution
10 (Service Continuity) and to all end consumers of electricity in Newfoundland and Labrador (End
11 Consumer).

12 Hydro has a relatively small population of distribution customers, who are widely dispersed
13 geographically. Customers are primarily located in rural and/or remote and isolated areas, which differs
14 from other utilities within its Electricity Canada comparator group, whose service territories are more
15 concentrated, which can reduce operational complexity and improve responsiveness to customer issues.⁶
16 For these reasons, Hydro's reliability metrics for Service Continuity are comparatively higher than the
17 Electricity Canada Region 2 average. The frequency of outages for Hydro's distribution customers is
18 generally stable, with an average of approximately five to six per year. The duration of outages is, on
19 average, 15–20 hours per year and is impacted by the remote nature of Hydro's operational area. Hydro
20 strives for incremental improvements in reliability for its distribution customers via prudent investment.
21 Hydro's historical Service Continuity SAIDI and SAIFI reliability trends are shown in Chart 2-1 and Chart 2-2.

⁶ Performance metrics are compared to Electricity Canada utility members in Region 2, which is defined as utilities that serve both urban and rural customers (urban/rural mix). Those include ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro-Québec, Manitoba Hydro, Maritime Electric, NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Sask Power, Elexicon Energy and Blue Mountain Power Corp.

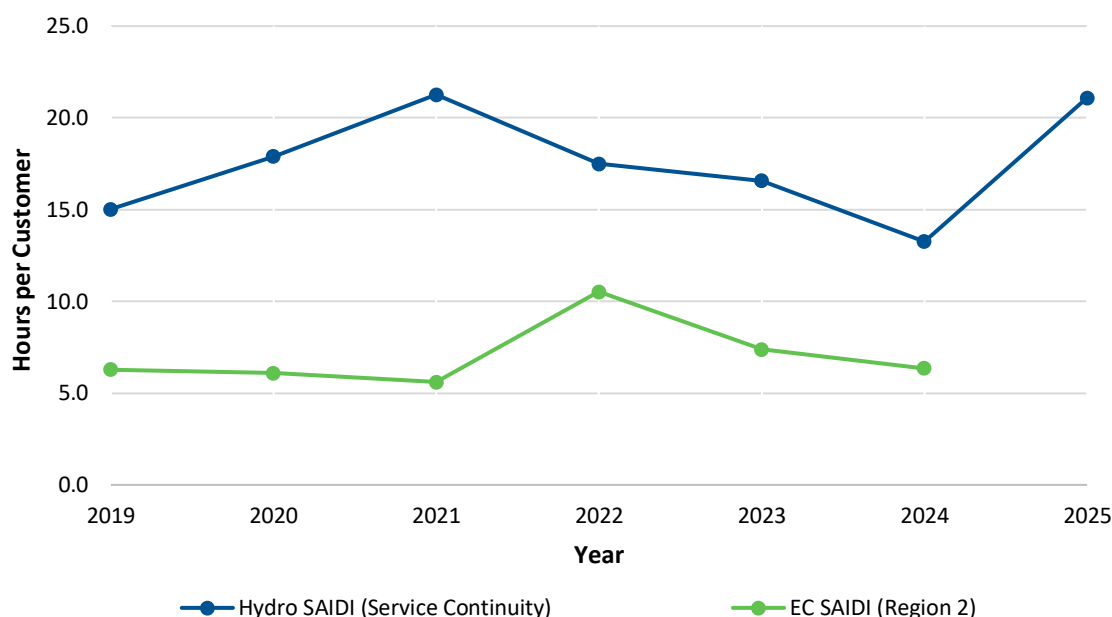


Chart 2-1: SAIDI (Hydro-Only) Performance 2019–2025^{7,8}

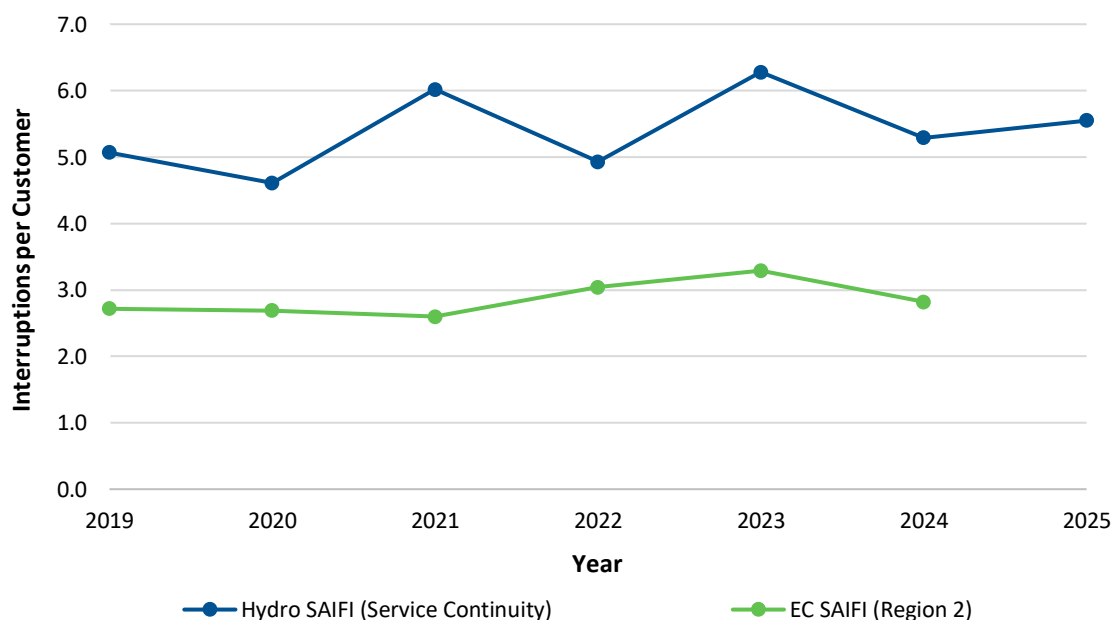


Chart 2-2: SAIFI (Hydro-Only) Performance 2019–2025^{9,10}

⁷ Excluding Major Events. Electricity Canada defines Major Events as “events that exceed reasonable design and/or operational limits of the electrical power system.”

⁸ Electricity Canada reliability data is not currently available for 2025.

⁹ Excluding Major Events.

¹⁰ Electricity Canada reliability data is not currently available for 2025.

- 1 The End Consumer Performance Index reflects the reliability of service to all end consumers supplied by
2 Hydro, including customers of Newfoundland Power affected by Hydro system events.¹¹ SAIDI and SAIFI
3 metrics for end consumers have remained relatively consistent over recent years, indicating stable
4 reliability performance across the system. Hydro’s historical SAIDI and SAIFI end consumer reliability
5 statistics are shown in Chart 2-3 and Chart 2-4.

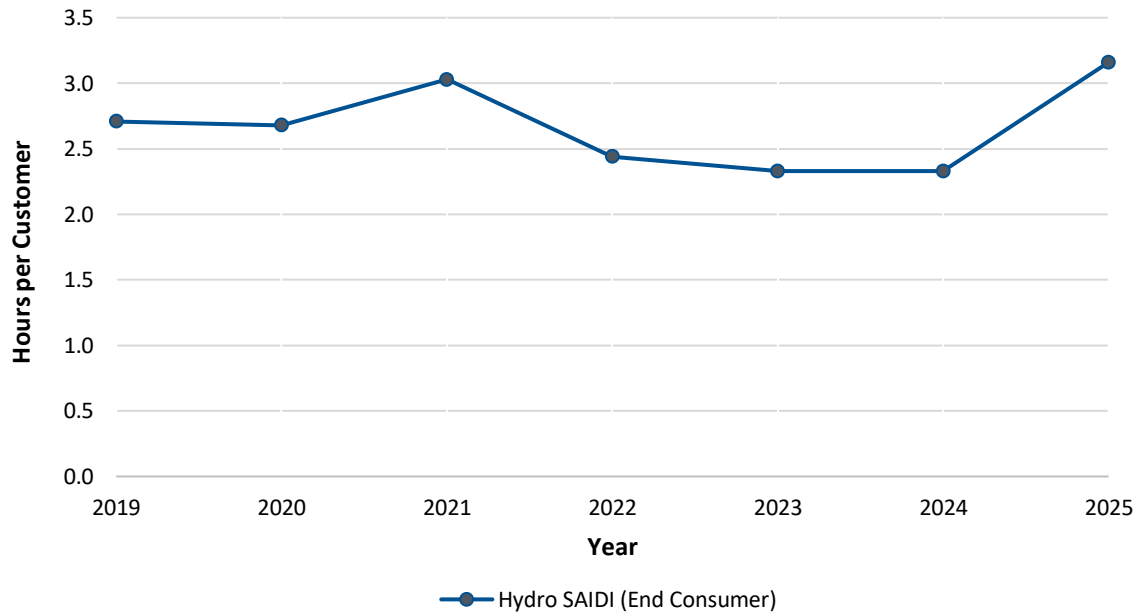


Chart 2-3: SAIDI (End-Consumer) Performance 2019–2025¹²

¹¹ Hydro developed the End Consumer Performance Index to measure the reliability of service to all end consumers of electricity in the province who are supplied by Hydro other than Hydro’s Industrial customers. Data are measures of the duration and frequency of service interruptions experienced as a result of Hydro system events.

¹² Excluding Major Events.

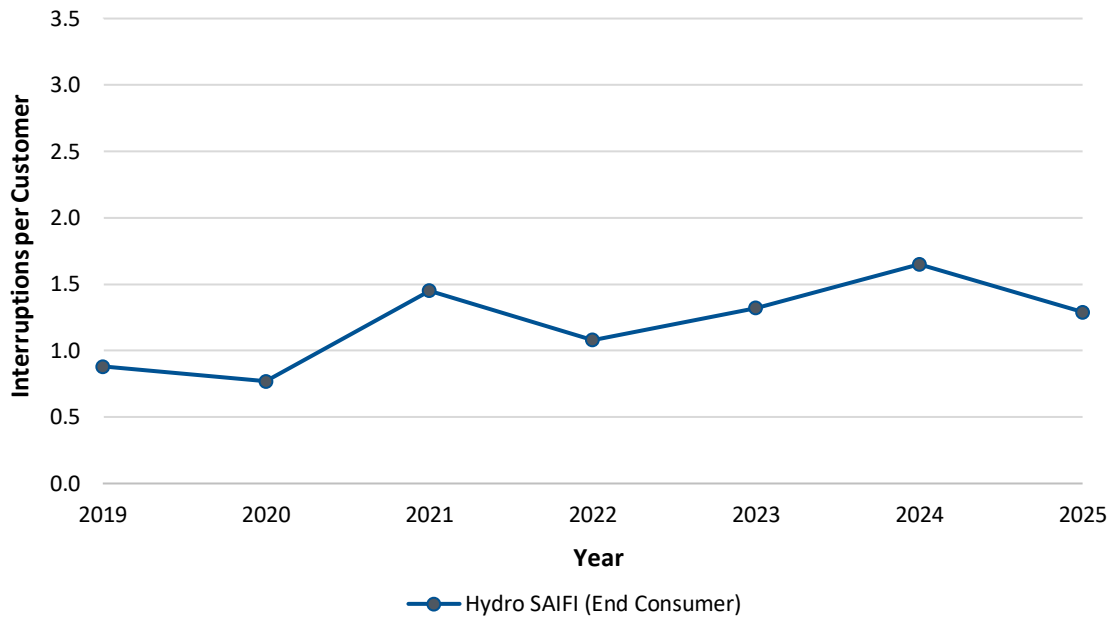


Chart 2-4: SAIFI (End-Consumer) Performance 2019–2025¹³

1 **Regulated Assets Generation Reliability**

2 Hydro’s weighted DAFOR performance in comparison to its Electricity Canada comparator group is shown
3 in Chart 2-5. For DAFOR, a lower percentage means outages are shorter or restored more quickly,
4 indicating better asset reliability. For the 2020–2024 period, Hydro’s average weighted DAFOR for
5 regulated assets of 8.27% compares favourably with the equivalently weighted national Electricity Canada
6 five-year average of 12.17%. In 2025, Hydro’s overall weighted DAFOR improved to 7.07%.

7 In the years when DAFOR trends higher, Holyrood TGS performance is a key driver, reflecting the aging
8 asset and the time to resolve more material equipment failures. Excluding Holyrood TGS, Hydro’s five-year
9 average improves to 2.83%.¹⁴

¹³ Excluding Major Events.

¹⁴ The higher DAFORs in 2021, 2023, and 2024 can be primarily attributed to the performance of aging units at Holyrood TGS and elevated DAFORs in Hydro generation, particularly Upper Salmon. When Holyrood TGS is excluded, Hydro’s five-year weighted DAFOR average is 2.83%, which includes hydraulic assets only. CT performance is measured using DAUFOP.

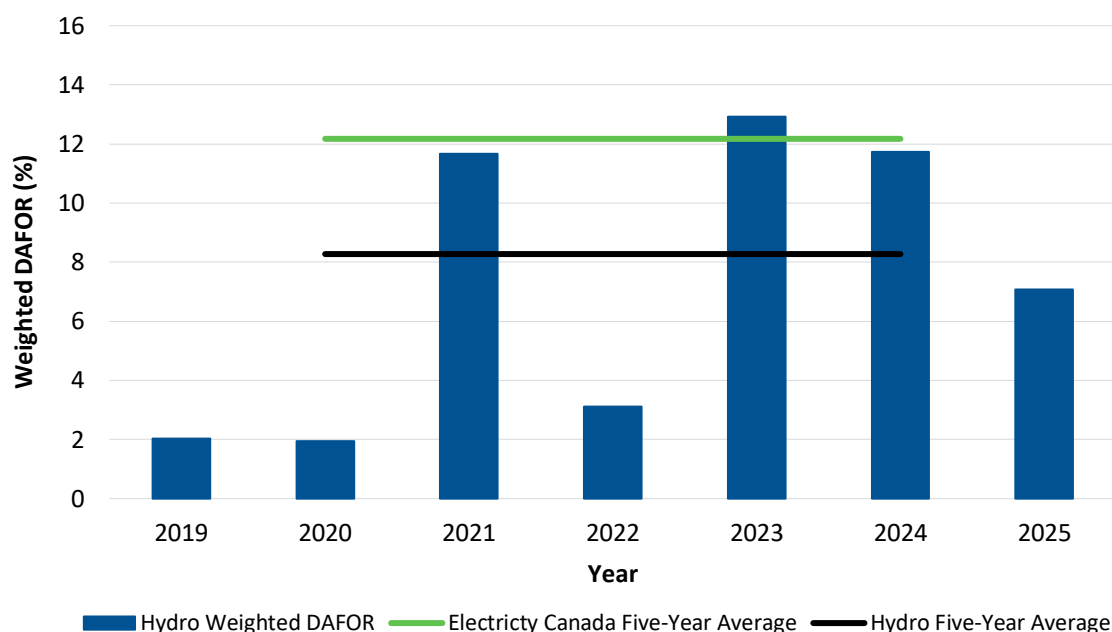


Chart 2-5: Weighted DAFOR (Regulated Assets)¹⁵

1 Muskrat Falls Assets Reliability

2 The performance of the Muskrat Falls Assets has steadily improved since commissioning, providing
3 increasingly reliable electricity to the provincial electricity system. In 2025, the LIL achieved an EqFOR of
4 1.30%.¹⁶ A lower EqFOR value means outages are occurring less frequently, are shorter or restored more
5 quickly, indicating better asset reliability. LIL high-power testing was successfully completed in late March
6 2026, and the LIL is now released to operate at its full capacity of 900 MW.¹⁷ LIL EqFOR since
7 commissioning is shown in Chart 2-6.

¹⁵ Electricity Canada reliability data for generation is not currently available for 2025.

¹⁶ As the 900 MW test has been completed, EqFOR is calculated on a LIL capacity of 900 MW. Hydro had previously reported this statistic as 0.96% calculated on a LIL base capacity of 700 MW in “Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended December 31, 2025,” Newfoundland and Labrador Hydro, February 5, 2026.

¹⁷ Prior to the completion of high-power testing, the LIL was rated at a base capacity of 700 MW. Performance was reported at both the 700 MW and 900 MW levels as shown in Chart 2-6.

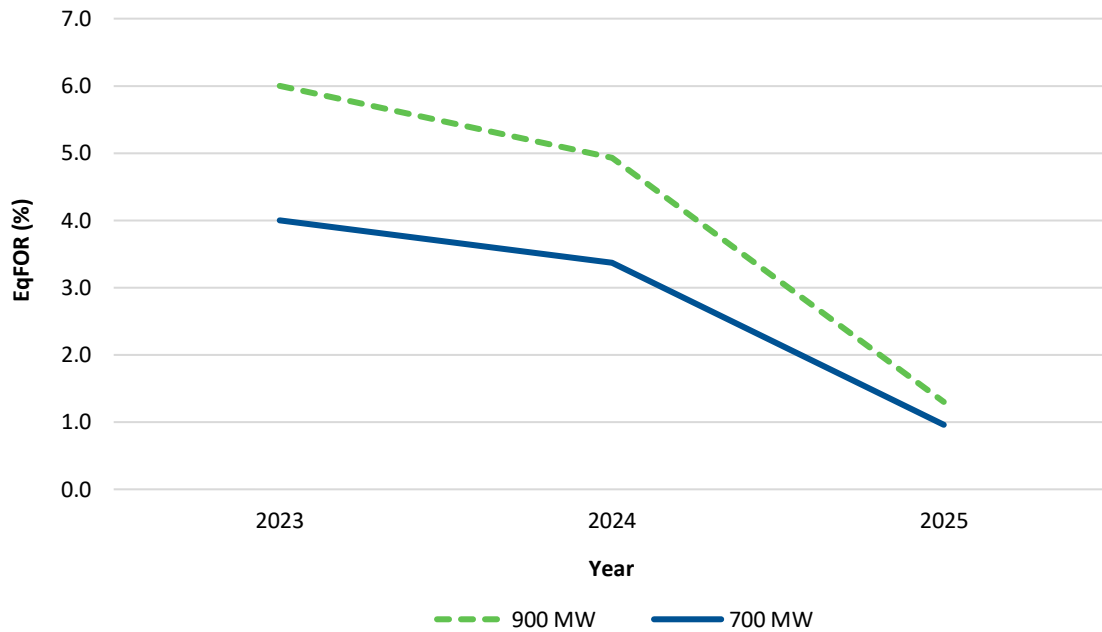


Chart 2-6: LIL EqFOR

- 1 The LIL performance has shown steady improvement since commissioning. This level of performance for
- 2 the early operation of the LIL is highly positive, and at the low end of the range of 1% to 10% that was
- 3 reflected by Hydro as part of the *Reliability and Resource Adequacy Study Review*.
- 4 Since commissioning, the Muskrat Falls Hydroelectric Generating Facility has been outperforming the
- 5 Electricity Canada five-year average of 6.03% for similar units across Canada. The four generating units
- 6 achieved a weighted DAFOR of 1.35% in 2025, as shown in Chart 2-7.

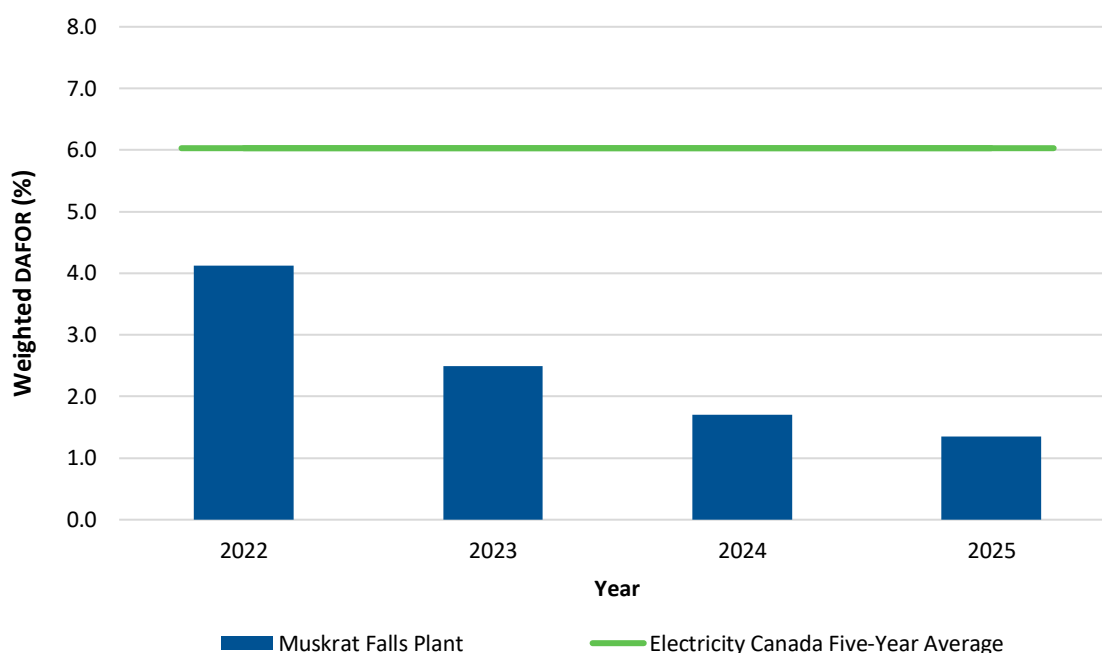


Chart 2-7: Muskrat Falls Hydroelectric Generating Facility Weighted DAFOR

1 Overall, Hydro's generation reliability has been outperforming Electricity Canada comparators, on average.
 2 Hydro's end consumer SAIDI and SAIFI statistics for transmission reliability performance have been
 3 consistent, demonstrating stable system performance. Customer surveys confirm that Hydro's reliability
 4 outcomes align with customer expectations. In the most recent surveys, 93% of Hydro's Residential
 5 customers and 86% of Hydro's General Service customers reported satisfaction with the reliability of
 6 electricity supply.

7 **2.1.3 Capital Investment**

8 Hydro is committed to investing responsibly in the electrical system to the benefit of its customers. A key
 9 consideration in all investment decisions is the impact on customer rates, with Hydro seeking to balance
 10 costs for customers with the continued delivery of reliable electricity service.

11 Since 2019, Hydro's total annual capital expenditures have averaged approximately \$140 million, including
 12 Major Projects in more recent years.¹⁸ This average is increasing as Hydro enters a period of heightened
 13 capital investment, driven in part by major life extension initiatives, such as the Bay d'Espoir penstocks.

¹⁸ For the purposes of this chapter, the term 'Major Project' is generally used to describe regulated projects and programs with an anticipated cost of \$50 million or greater under the accountability of Hydro's Major Projects division.

Historically, Hydro’s capital program was largely sustaining in nature, focused on refurbishing aging assets to maintain system reliability and maximize asset life. While asset renewal remains fundamental, growth-related investments are also necessary to enable the retirement of aging infrastructure and ensure the system continues to reliably serve customers. This results in an upward trend in spending over the 2024–2027 period, as illustrated in Chart 2-8, with forecasted spending of \$284 million in 2026 and \$532 million in 2027.¹⁹

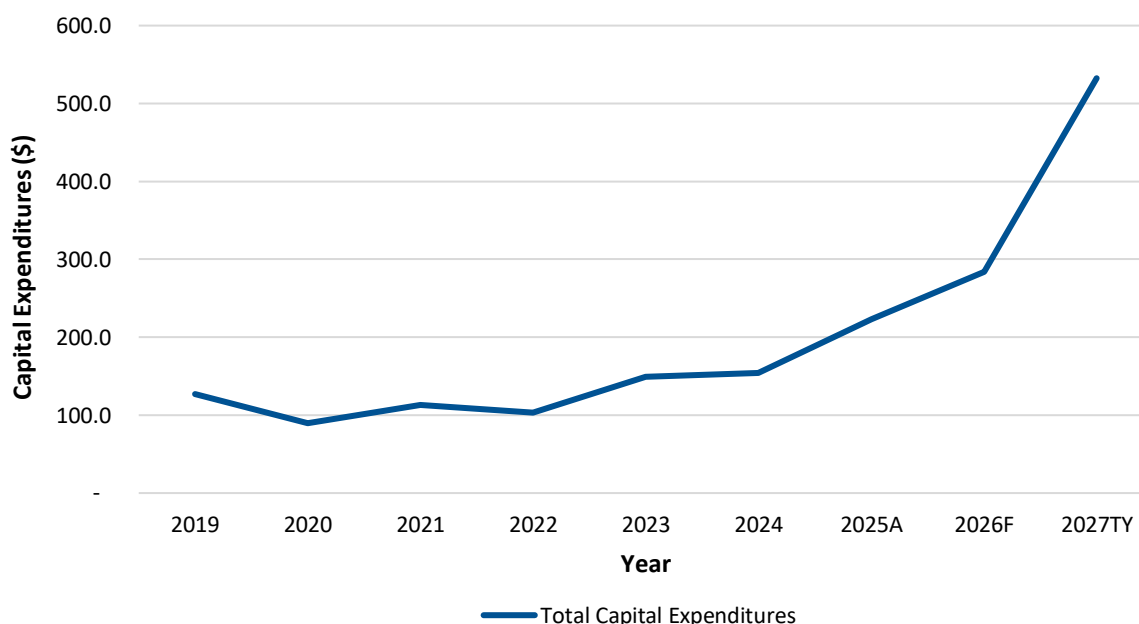


Chart 2-8: Actual and Forecast Capital Expenditures 2019 to 2027 (\$ Millions)

Recognizing the scale of planned capital investment and broader cost-of-living pressures faced by customers, Hydro reduces or defers capital investment, where appropriate, as discussed in Section 2.4.4.

2.1.4 Hydro’s Load Forecast

Hydro’s load forecasts reflect a combination of direct input from Industrial customers and Hydro’s Utility customer, Newfoundland Power, as well as Hydro’s internal load forecasts for Newfoundland Power, and the Rural Interconnected and Isolated systems. Total load requirements are then determined from analyses of overall system losses, station service and demand diversity, allowing for the development of

¹⁹ 2026 Forecast and 2027 Test Year Forecast differ slightly from the 2026 CBA. Hydro utilized the five-year plan from the 2025 CBA with adjustments for Major Projects and updated project estimates, as required, as input to the 2026 GRA.

appropriate coincidence factors.²⁰ An overview of the 2026 GRA load forecast and sources of supply for each system is provided as Exhibit 4.²¹ The load forecast included in this evidence is for the purpose of rate setting for this GRA and the proposed 2027 Test Year; it does not reflect the longer-term reliability requirements of the system currently being examined in other proceedings before the Board and for which the associated rate impacts will be examined in future GRAs.

The 2027 Test Year load forecast utilizes a revised load forecast scenario that is based on the Reference Case load forecast²² within the 2025 Load Forecast Report,²³ adjusted to reflect updated industrial demand. Actual energy requirements from 2019 through 2024, and the operating load forecasts for 2025, 2026, and the 2027 Test Year load forecast for the Island Interconnected System, Labrador Interconnected System and Isolated systems are provided in Schedules A-I, A-II and A-III, respectively.

Overall, Hydro’s provincial load forecast for the purposes of rate setting has changed by less than 1% from the 2019 Test Year to the 2027 Test Year.²⁴ Table 2-1 summarizes the overall forecast percentage changes for Hydro’s electricity systems for the 2027 Test Year in comparison to the 2019 Test Year.

Table 2-1: Change in Hydro’s Electricity System Requirements for the 2027 Test Year²⁵

	2019 Test Year (GWh)	2027 Test Year (GWh)	Change (%)
Island Interconnected System	7,202	7,417	3.0
Labrador Interconnected System	2,971	2,810	(5.4)
Isolated Systems	81	79	(2.1)
Total Electricity Requirements	10,253	10,306	(0.5)

²⁰ The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System, it provides a measure of the relative contribution of the Island Interconnected System and the Labrador Interconnected System peaks to the combined Newfoundland and Labrador Interconnected System peak.

²¹ The supporting hydrological study provided by Hatch Ltd. is provided as Exhibit 5.

²² This scenario is the expected load growth case, reflective of expected industrial load, electricity prices, population growth and current/committed government decarbonization policies and programs.

²³ For further information, please refer to “2025 Island Interconnected System Load Forecast Report,” Newfoundland and Labrador Hydro, November 5, 2025.

²⁴ The 2025 Load Forecast Report covers the period 2026 to 2036. The compound annual growth rate in the Reference Case for the Island Interconnected System is 1.1%. The proposed additions of Bay d’Espoir Unit 8 and the Avalon CT, which are currently before the Board in the 2025 Build Application, represent the first step toward retiring aging assets, maintaining system reliability and meeting the electricity demand within the Reference Case scenario. For a full synopsis of the 2025 Load Forecast Scenario demands, please refer to the “2025 Island Interconnected System Load Forecast Report,” Newfoundland and Labrador Hydro, November 5, 2025, p. iv, Chart 1.

²⁵ Numbers may not add due to rounding and percentages may not recalculate. Please refer to Exhibit 4.

For the 2027 Test Year, Hydro is forecasting slightly higher energy requirements on the Island Interconnected System of 215 GWh relative to the 2019 Test Year. The increase in load is due to higher energy requirements for Newfoundland Power, Hydro Rural Interconnected, and system losses, partially offset by lower Industrial customer requirements.

For the 2027 Test Year, Hydro is forecasting a decrease in energy requirements for the Labrador Interconnected System of 161 GWh relative to the 2019 Test Year. This reflects lower Industrial customer loads, Hydro Rural Interconnected load, and system losses. The 2019 Test Year also included 61 GWh of data center growth related to cryptocurrency mining, which is no longer reflected in Hydro's firm requirements, in line with Government direction that Hydro is not obligated to supply firm power to cryptocurrency customers.²⁶

Total electricity requirements across Hydro's Isolated systems are lower in the 2027 Test Year compared to the 2019 Test Year by 1.7 GWh. While there is growth in some Isolated systems, the overall energy requirements have declined. This decline is largely driven by decreases in electricity usage of approximately 1.5 GWh or nearly 20% within the Isolated systems on the Island when comparing the 2027 Test Year to the 2019 Test Year. CDM initiatives,²⁷ general population decline and community relocations, such as Little Bay Islands,²⁸ have contributed to the reduction in the Island Isolated system load since the 2019 Test Year.

2.2 Operating the System

Operating the provincial electricity system requires the coordinated management of generation, transmission, imports and exports, and demand in real time to reliably serve customers at the lowest possible cost. As the provincial system has grown in scale and complexity, effective system operations have become central to delivering the least cost electricity while maintaining reliability and environmental responsibility.

Effective system management, including the avoidance of operational risk that can increase costs or impact reliability, depends on experienced personnel and the utilization of enabling technologies. Hydro's

²⁶ Government of Newfoundland and Labrador, *Order in Council OC2022-266*, November 10, 2022.

²⁷ In 2025, CDM initiatives through the Isolated Communities Energy Efficiency Program resulted in more than 1,000 MWh of energy savings. For more information, please refer to "Electrification, Conservation and Demand Management Report – For the Year Ended December 31, 2025," Newfoundland and Labrador Hydro, April 10, 2026.

²⁸ The community of Little Bay Islands relocated in 2019.

staff work collaboratively, using real-time data and established decision-making processes to optimize the use of hydrological resources, minimize reliance on higher-cost thermal generation, manage operational risk, and respond effectively to system events.

This section describes how Hydro effectively operates the provincial electricity system by integrating process, people and technology. By operating the system in this coordinated and disciplined manner, Hydro improves operational efficiency, reduces reliance on higher-cost resources, and limits risks and costs that would otherwise be reflected in customer electricity rates.

2.2.1 Dispatch of Least-Cost Electricity

Hydro's system has become increasingly complex since its last GRA, with the integration of the Muskrat Falls Assets and the interconnection to the North American grid through the Maritime Link. The NLSO is responsible for safely and reliably managing the provincial electricity system in real time. In operating the system, Hydro ensures that the security of supply for domestic load remains paramount and continually looks for opportunities to optimize system operations in ways that deliver reliable, least-cost electricity and cost savings for customers, while doing so in an environmentally responsible manner.

Hydro operates its electricity system using the principle of economic dispatch, meaning it schedules and controls its generating units so that electricity demand is met at the lowest possible cost while maintaining system reliability and respecting system constraints. In practice, this involves prioritizing the use of lower-cost generation resources such as hydroelectric facilities whenever they are available, and only calling on higher-cost units, like CTs, when necessary to meet demand.

Dispatch decisions take into account water management requirements, generator operating limits, transmission constraints, contractual export commitments, and reliability requirements, ensuring that the system is protected and secure while minimizing costs to customers.

Island Interconnected System

Hydro meets system demand using a combination of hydroelectric generation, power purchases, LIL deliveries, thermal generation from Holyrood TGS, standby units, and imports.

Thermal and standby generation are dispatched only when required to meet demand and reserve requirements, thereby minimizing fuel costs and emissions. As the Island Interconnected System is connected to Labrador via the LIL, Muskrat Falls generation is scheduled such that it keeps production at

Holyrood TGS at a minimum and helps meet Island demand. At the commencement of the spring period in 2026, Hydro was able to reduce reliance on Holyrood TGS by reducing operations down to one unit, as planned. This reduces reliance on thermal generation and associated fuel usage, resulting in cost savings for customers.

In the 2027 Test Year, expected use of No. 6 fuel at the Holyrood TGS is about one-third of the level forecast for the 2019 Test Year. This reduction lowers No. 6 fuel costs by \$129.7 million.²⁹ Hydro will continue to minimize thermal generation wherever possible, particularly following the successful 900 MW LIL high-power test in March 2026 and as additional assets come into service over time.

Chart 2-9 demonstrates that Hydro has been able to reduce reliance on the Holyrood TGS between test years.

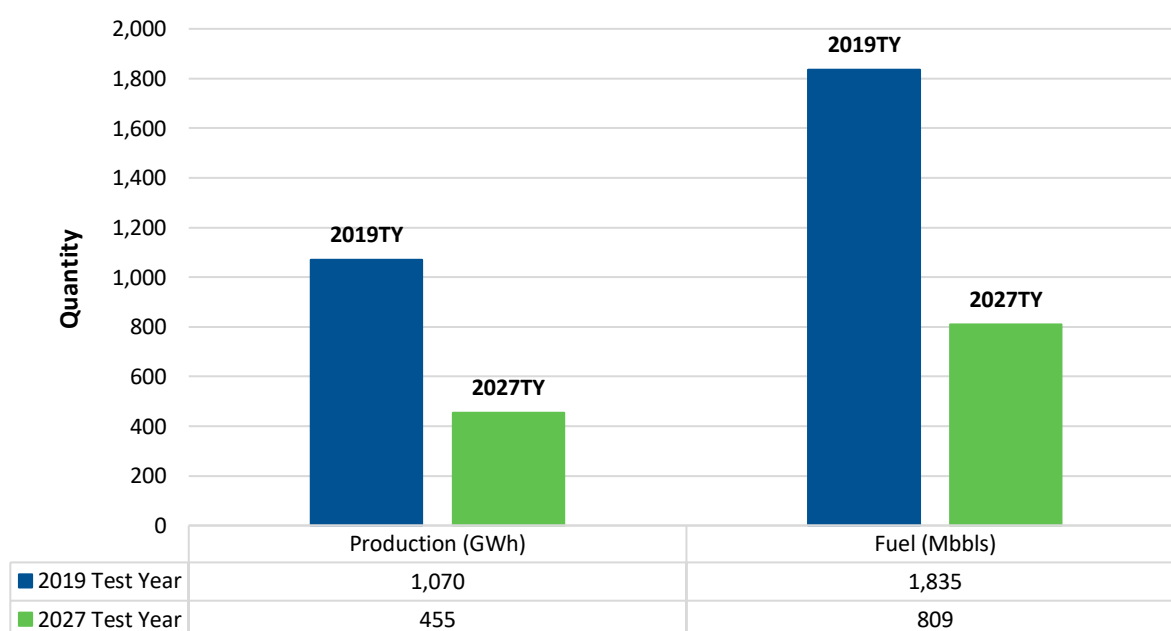


Chart 2-9: Holyrood TGS Production and No. 6 Fuel Consumption³⁰

While Hydro relies on standby generation as critical resources for meeting peak demand, providing emergency backup, addressing localized supply needs, supporting planned transmission outages, and supporting synchronous condensing requirements, these units are typically dispatched only when

²⁹ 2019 Test Year No. 6 Fuel Costs (\$194.7) – 2027 Test Year No. 6 Fuel Costs (\$65.0) = \$129.7. For further discussion on fuel, please refer to Chapter 5, Section 5.2.1.

³⁰ 1 Mbbls is equivalent to 1,000 barrels of No. 6 fuel.

electricity demand or reserve requirements cannot be met by hydroelectric generation, LIL deliveries to the Island, or the Holyrood TGS.

Economic dispatch is supported by a daily “day ahead” dispatch plan, which provides the NLSO with expected generation schedules based on forecasted demand, available resources, planned outages, meeting firm contractual export commitments, and reservoir management requirements. The plan is designed to:

- Ensure firm load is served;
- Minimize water spill;
- Maximize hydroelectric efficiency;
- Maximize use of renewable energy; and
- Minimize thermal and standby generation, thereby reducing fuel costs.

A key input into the day-ahead dispatch is the Water Management Guidelines, which are developed weekly and outline the system’s generation priorities, the priority order for generation reductions or increases to mitigate spill risk, planned unit shutdowns, and guidance on discharge operations to provide clear operational direction of Hydro’s hydroelectric facilities. The guidelines also identify when import or export opportunities may be sought by Energy Marketing.³¹ These guidelines are informed by Water Management’s broader mandate to plan, coordinate, and optimize Hydro’s hydroelectric resources to ensure a reliable, least-cost supply of electricity while meeting regulatory, contractual, and environmental obligations. They are supported by advanced system modeling that incorporates load forecasts, hydrological conditions, infrastructure outages, and system constraints, as well as ongoing monitoring of meteorological and hydrological conditions, ensuring that dispatch decisions economically reflect both short-term operational requirements and longer-term reservoir management objectives.

In addition, now that the system is connected to the North American grid through Nova Scotia via the Maritime Link, Hydro has the ability to import non-firm energy to economically offset the requirement to produce additional thermal energy, or support reservoir storage, should the LIL bipole be unavailable.

³¹ In Board Order No. P.U. 49(2018), the Board approved a Pilot Agreement. The intent of the Pilot Agreement is to optimize Hydro’s hydraulic resources through the strategic use of its storage capabilities, taking advantage of the variability of energy pricing in external markets over time. This includes effective management and execution of ponding operations to optimize the storage capability of Island Interconnected System reservoirs or spill avoidance.

Imports, when available, can occur through a combination of day-ahead commitments and real-time transactions; however, they are not forecast to occur during the 2027 Test Year, as the deliveries are considered non-firm.³²

Labrador Interconnected System

On the Labrador Interconnected System, Hydro supplies customers in Labrador East and Labrador West with electricity purchased from CF(L)Co, via the TwinCo and Recapture Blocks. When Muskrat Falls generation is more than sufficient to meet LIL deliveries to the Island, it can supplement the Labrador load requirement.³³

The operation of the Churchill River system, which includes both the Churchill Falls and Muskrat Falls hydroelectric stations, is optimized through the use of daily coordinated production schedules for each facility. The hourly schedules ensure alignment with contractual commitments and system requirements.

Isolated System

Hydro operates remote diesel plants across the province to supply electricity to customers on its Isolated systems. Where possible, diesel generation is supplemented by renewable energy through PPAs. In the 2027 Test Year, approximately one-third of the Isolated system load is forecasted to be supplied by renewable generation.

Hydro has established eight PPAs for renewable energy within its Isolated systems, including agreements with Hydro-Québec for the L'Anse-au-Loup system, and St. Mary's River Energy for the Mary's Harbour system. Additional renewable generation is provided through nine solar photovoltaic installations located in Hopedale, Rigolet, Nain, Postville, St. Lewis,³⁴ Port Hope Simpson, Cartwright, and Black Tickle. These

³² Since the 2019 Test Year was compiled, it was determined that planning for imports over the Maritime Link is not a feasible option. Transmission paths to gain access to potential markets are largely committed, and neighbouring jurisdictions do not have surplus capacity to export. Therefore, Hydro does not include any long-term plan for Maritime Link imports for production planning purposes, and they are not included in the 2027 Test Year. This confirmation does not preclude opportunities on a short-term (spot market) basis for firm capacity or non-firm energy to meet capacity or energy requirements for the Island Interconnected System.

³³ As reported in Hydro's Supply Cost Variance Deferral Account Monthly Reports, Muskrat Falls and Hydro entered into a PPA for the purchase and sale of Residual Block Energy in February 2022. Under this agreement, Labrador Interconnected, Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, may now be serviced with energy from the Muskrat Falls Hydroelectric Generating Facility for the purpose of creating incremental Recapture Energy for export. The price paid by Hydro does not change as a result; therefore, customers are kept whole.

³⁴ St. Lewis includes two solar photovoltaic installations.

PPAs enable Hydro to supply electricity to customers in isolated communities at a lower cost than diesel generation while also reducing environmental impacts, in accordance with Hydro’s mandate.

2.2.2 Maximizing Value of Energy

Once the security of supply for domestic load is met, Hydro seeks to optimize the use of its hydrological resources. The role of Energy Marketing is to maximize value creation opportunities that arise due to the connection of the Island system with the broader North American grid. This is done through imports and exports. Export profits generated by Hydro are used to benefit customers either directly by offsetting Hydro’s supply costs or through the funding of rate mitigation.

Energy Marketing imports and exports energy for the Island for two primary purposes: (i) supporting system reliability; and (ii) optimizing the value of Hydro’s reservoir storage. From a system reliability perspective, having the option to import supports Hydro in managing its hydrological resources by reducing hydro generation and thus conserving reservoir storage during periods of low hydrology, or importing energy to provide a supplemental supply during times of shortfall, helping to avoid customer outages. During periods of high inflows, Energy Marketing may be requested to export energy to reduce the risk of reservoir spill, ensuring that energy which may otherwise be lost is monetized. From an Island storage optimization perspective, Energy Marketing utilizes importing and exporting to support ponding activities by purchasing energy during lower-priced periods and selling energy during higher-priced periods. This approach maximizes the value of Hydro’s stored water resources and allows Hydro to take advantage of favourable market pricing opportunities to generate additional value for customers.³⁵ In 2025, Energy Marketing generated \$160 million for customers through export sales. Proceeds from actual exports for the past five years, which are net of transmission costs, Energy Marketing operating costs and other expenses, are shown in Chart 2-10.

³⁵ Pursuant to the Pilot Agreement, exporting when system load is low allows for increased generation from Island hydraulic facilities and the utilization of water (energy) that would have otherwise been spilled, while not increasing the risk of spill elsewhere in the system. The Third Amended and Restated Pilot Agreement for the Optimization of Hydraulic Resources was approved as per Board Order No. P.U. 35(2022) and was extended as per Board Order No. P.U. 30(2023), Board Order No. P.U. 29(2024), and again in Board Order No. P.U. 37(2025).

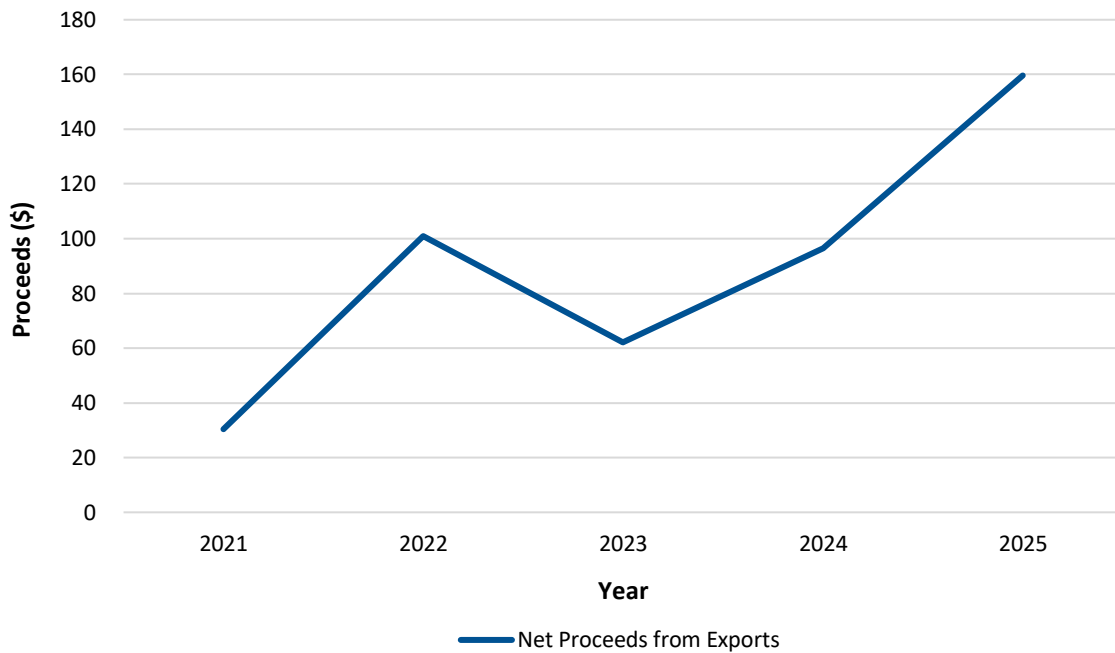


Chart 2-10: Value for Customers Generated by Energy Marketing (\$ Millions)

To ensure the most economic use of the energy generated by Hydro, Energy Marketing closely monitors market conditions and system import and export capability to determine the optimum timing and volume for external market transactions.

Energy Marketing schedules these transactions with external markets and counterparties in one of two ways: (i) spot markets, which are day-ahead or real-time energy markets where prices are updated hourly (including markets in New York (NYISO) and New England); and (ii) contract market pricing, where Hydro has established mutually agreed bilateral contracts.³⁶ Contract markets can include Québec, New Brunswick and Nova Scotia, in addition to spot markets. Due to the capacity and energy constraints facing all of the aforementioned provinces, Hydro has not secured a bilateral contract for energy in recent years and conducts the majority of its transactions through spot markets.³⁷

By combining, or “pooling,” generating sources and reservoirs, Hydro achieves the best opportunity to maximize the value of resources and maximize rate mitigation for customers. For instance, where

³⁶ A bilateral contract is a negotiated agreement between one buyer and one seller to exchange a specific amount of electricity at an agreed price for a specific time.

³⁷ Hydro contacts NS Power and NB Power annually to assess long-term firm energy potential, and to date, both utilities confirm that acquiring a firm import contract during the winter period is not feasible in the near term. Updates are provided in the annual Near-Term Generation Adequacy reports.

appropriate and when there is excess available, Hydro will utilize Muskrat Falls energy to supply the Labrador Interconnected System and export the Recapture Energy, which would otherwise have been used to serve these customers. This approach enables additional Recapture Energy exports to external markets and maximizes the value of Hydro’s hydrological resources for customers.

Through mechanisms such as energy “banking” and “de-banking” under the Churchill River Water Management Agreement, Hydro can store energy that would otherwise be spilled and use, or export it, at a later time.³⁸ This optimizes resource utilization and can generate revenues that benefit customers by directly contributing to rate mitigation. For example, on behalf of Muskrat Falls, in recent years, Hydro sold energy banked in the Churchill Falls reservoir system out of province.³⁹

2.2.3 Enhancing Technology Solutions

Utilization of technology enables Hydro to mitigate business risk, drive system reliability and increase employee productivity. As part of improving its system operations for customers, Hydro has focused on reviewing operational and information technologies specific to business applications, communication equipment, and infrastructure that are currently used at Hydro, as well as those used by other utilities. Opportunities to enhance technological solutions already in service at Hydro and implement new solutions that lead to reduced costs for customers (e.g., mobility solutions, asset inspections, etc.) are identified and discussed in Section 2.4.5.

Utilizing outdated IT infrastructure introduces cost and risk to the organization as a result of higher administrative and support activities, impacting day-to-day operations. Utilizing aging IT infrastructure, which lacks supportability, increases Hydro’s cybersecurity risks, increases the likelihood of asset stranding, and increases the risk of loss of critical business functions.

Hydro has also focused on cybersecurity, which has mitigated organizational risk and avoided costly cybersecurity attacks, which pose a risk to Hydro, Government, and electricity customers. Cybersecurity events within the utility industry and across Canada in general have cost companies millions of dollars,⁴⁰

³⁸ De-banking of this energy to meet demand is not forecast to occur during the 2027 Test Year, as the deliveries are considered non-firm.

³⁹ The delivery of additional blocks of energy was agreed to in 2023, with a total of 1.9 TWh delivered between 2024 and 2025.

⁴⁰ Halifax Examiner, “Nova Scotia Power profits drop due to cyberattack,” November 10, 2025, <https://www.halifaxexaminer.ca/economy/utilities/nova-scotia-power-profits-drop-due-to-cyberattack/#:~:text=The%20Company%20maintains%20cyber%20insurance,related%20to%20the%20Cybersecurity%20Incident.>

jeopardized the personal information of employees and customers⁴¹ and put the operation of the broader electricity grid at risk.⁴²

Hydro is focusing its efforts on strengthening system security, increasing monitoring, completing incident preparedness training exercises, and increasing awareness of targeted social engineering.

2.2.4 Attraction and Retention of a Qualified Workforce

Attraction of a qualified workforce, limiting turnover, and supporting employee engagement are key risk mitigation strategies for the provision of safe, reliable, least-cost electricity service. As a vertically integrated electric utility, Hydro requires a highly skilled and specialized workforce that is competent to navigate the inherent hazards within the utility industry. The execution of this work requires personnel with expertise in areas such as power system operations, protection and control, system planning, asset management, engineering, environmental compliance, cybersecurity, and safety management. Specialized personnel ensure that assets are operated in accordance with *Good Utility Practice*, regulatory and legislative requirements are met, and operational risks are effectively managed.

As Hydro's organization and the provincial energy landscape are evolving, labour resources are required to support Hydro's major capital investments and maintain existing assets. At the same time, Canada's aging workforce is experiencing a high number of retirements, and the labour market is highly competitive.⁴³ According to Electricity Human Resources Canada, employment in Canada's electricity sector is anticipating nearly 28,000 job openings by 2028, due to expansion and retirements. An estimated 12,000 of those jobs will be related to expansion.⁴⁴

Employee Compensation and Benefits

Compensation and benefits that are competitive within the Atlantic Canadian utility market are critical to attracting and retaining the qualified workforce required to ensure Hydro can operate the system, serve its customers and fulfil its legislated mandate. Since the last GRA, Hydro has continued to actively manage

⁴¹ Cybersecurity Dive, "Suncor Energy confirms hackers breached Petro-Canada gas stations' customer rewards data," July 6, 2023, <https://www.cybersecuritydive.com/news/suncor-hackers-breached-petro-canada-customer-data/685365/>.

⁴² Nova Scotia Power, "Our Commitments: Office of the Privacy Commissioner of Canada investigation," March 25, 2026, <https://www.nspower.ca/about-us/articles/details/articles/2026/03/25/our-commitments--office-of-the-privacy-commissioner-of-canada-investigation>.

⁴³ Statistics Canada, "Majority of people planning to retire would continue working longer if they could reduce their hours and stress," Government of Canada, August 1, 2023, <https://www150.statcan.gc.ca/n1/daily-quotidien/230801/dq230801a-eng.htm>.

⁴⁴ "Electricity in Demand: Labour Market Insights 2023–2028," Electricity Human Resources Canada, <https://ehrc.ca/wp-content/uploads/2024/05/Electricity-in-Demand-Labour-Market-Insights.pdf>.

its labour costs in line with direction from the Board and Government, while facing significant inflationary pressure and increased competition for talent. Approximately 5% of Hydro’s workforce is currently eligible for retirement. The management of Hydro’s workforce, both in size and with respect to compensation, requires Hydro to balance labour costs with the risks associated with inadequate resources impacting safety, reliability and employee engagement.

Significant compensation matters impacting labour costs in the period since the last GRA include:

- No economic increases to non-union employee salaries from 2016–2022;
- Evaluation of appropriate comparator group in 2018;⁴⁵
- Removal of short-term incentives and lump sum merit payments for all non-union and executive employees in 2021;
- Reduction of the total number of executive positions by approximately 50% in 2021, including the merging of several positions;
- Adjustments to executive salary scales in 2021; and
- Removal of executive vehicle allowances in 2021.

A key mitigation to employee recruitment and retention risks is providing fair compensation. To inform its efforts, Hydro undertakes a market review of its compensation structure and the competitor market every three to five years.⁴⁶ Hydro targets the 50th percentile as the competitive position within its comparator market.⁴⁷ This approach balances the need to remain competitive in the utility industry in order to attract and retain the skills required to manage the utility according to *Good Utility Practice*, while recognizing Hydro’s role as a Crown corporation.

Working with Government, a comprehensive third-party review of Hydro’s non-union and executive compensation was completed by Southlea in 2024 and is provided as Exhibit 6. Southlea found that the appropriate comparator group for Hydro is other Canadian utilities, including both government-owned and investor-owned utilities (restricted to similarly sized utilities for executives, including the Chief

⁴⁵ Hydro’s non-union salary scales were reviewed in 2018, and most were adjusted downward to align more closely with the Utilities comparator group (consisting of comparable Canadian utilities with an Atlantic regional market adjustment applied) versus the General Industry comparator previously used.

⁴⁶ Hydro plans to undertake its next market review in 2027.

⁴⁷ 50th percentile is the median value in a dataset.

Executive Officer and Vice Presidents, and adjusted for the Atlantic compensation market differential). Southlea’s review determined that Hydro was 12% below the market 50th percentile of the utility comparator group on a total remuneration⁴⁸ basis for non-union, non-executive workforce in 2023, and approximately 50% below the market 50th percentile for executive compensation on a total remuneration basis, based on 2023 data. Southlea noted that Hydro was likely further below market in 2024,⁴⁹ and recommended that Hydro adjust compensation levels to keep pace with comparators in 2024 and avoid falling further behind the market:

Align to 2024 compensation levels which are anticipated to be 3.5% to 4.0% higher than the 2023 compensation data contained in this analysis, to avoid further misalignment with market. If no adjustment is made to the Hydro salary structure, total remuneration market differentials could reach 15%+, a level indicating significant misalignment with talent attraction and retention challenges expected.⁵⁰

To address survey outcomes and start to realign its position with its comparator market, Hydro increased its compensation levels, administering economic increases of 4% in 2024 and 4% in 2025. As noted by Southlea, other utilities were providing further increases to salaries during this time period. Accounting for those increases, Hydro continued to be approximately 11% below the 50th percentile target at the end of 2025.⁵¹

Hydro’s current compensation administration practices reflect a moderate and measured approach, reflective of its role as a crown utility. Hydro has forecasted modest salary adjustments through its 2027 Test Year that are required to continue to close the gap with Atlantic Canadian utility comparators as outlined in the Southlea report. Utility competitive compensation is necessary to attract and retain employees with the key skills required to meet Hydro’s statutory obligations for reliable, least cost service to customers. Increases in labour operating costs in the 2027 Test Year are partially offset by the capitalization of certain salaries, as approved through Hydro’s recent application to capitalize general expenses.⁵²

⁴⁸ Total Remuneration = Salary + Variable Pay (if applicable) + Employer-Provided Pension & Benefit Values.

⁴⁹ “Total Compensation Program Review – Part II,” Southlea Group LP, June 21, 2024, p. 3.

⁵⁰ “Total Compensation Program Review – Part II,” Southlea Group LP, June 21, 2024, p. 5.

⁵¹ Compensation adjustments implemented by Hydro in 2024 and 2025 were positive; however, they had a smaller effect on Hydro’s positioning relative to the market due to the impact of the prior seven-year wage freeze and market movement in more recent years, which has been driven by high levels of inflation.

⁵² 2027 Test Year labour costs are net of \$6.6 million capitalized salaries as a result of Board Order No. P.U. 32(2025).

Workforce Resourcing and Planning

Workforce management is founded on having the right workforce complement at the right time. Hydro has increased its workforce only as required to oversee the provincial electricity grid through a period of substantial change. The pace and volume of human resources which Hydro adds to the organization considers cost, expertise available within the organization, advanced planning and engineering requirements, lead times associated with construction and integration of assets, efforts to build Hydro's talent pipeline from within and timing of required regulatory processes, among other considerations.

In late 2022, Hydro communicated a need for new capacity solutions to meet future system requirements, which would require the identification of the least-cost option(s) and the development of an application to the Board for approval of related capital expenditures. As a result, Hydro's labour requirements reflected a need for growth in a modest and measured manner. In August 2023, the Board directed Hydro to "ensure adequate resources are dedicated so that there is no further slippage in the schedule and also to seek and implement opportunities to advance the schedule for the completion of the identified studies, the filing of an application and the implementation of new generation." To ensure adequate resources, Hydro had to increase its workforce or otherwise take resources away from other critical activities, which would not be prudent.

To support the work required now and into the future, Hydro's FTE complement is increasing by approximately 5.6%⁵³ over the eight-year period between test years. Hydro's current and future workforce requirements are driven by its operational and capital requirements and are assessed on an annual basis utilizing workforce planning practices. Growth in its workforce in recent years has primarily reflected major capital investment requirements, electrification, internal talent pipeline development, and succession planning for key and critical roles.

In 2023, Hydro added a Major Projects division focused on the governance, planning and execution of major capital investments. The establishment of the Major Projects division is prudent and necessary to provide the level of oversight required for success in large projects.

The Major Projects division will support the growth and retention of expertise needed to execute major capital investments within Hydro for the long term. Additional support is also required within other

⁵³ 2027 Test Year FTEs (882) - 2019 Test Year FTEs (835) / 2019 Test Year FTEs (835) = 5.6%.

1 existing departments to progress consultant studies, resource planning analyses and regulatory processes
2 associated with the development and execution of Hydro’s system expansion requirements. As shown in
3 Chart 2-11, in the 2027 Test Year, without the impact of these additional FTEs, Hydro FTEs generally
4 remain flat relative to the 2019 Test Year levels. Incremental resourcing requirements to support Hydro’s
5 major capital investments are also reflected in Chart 2-11.⁵⁴

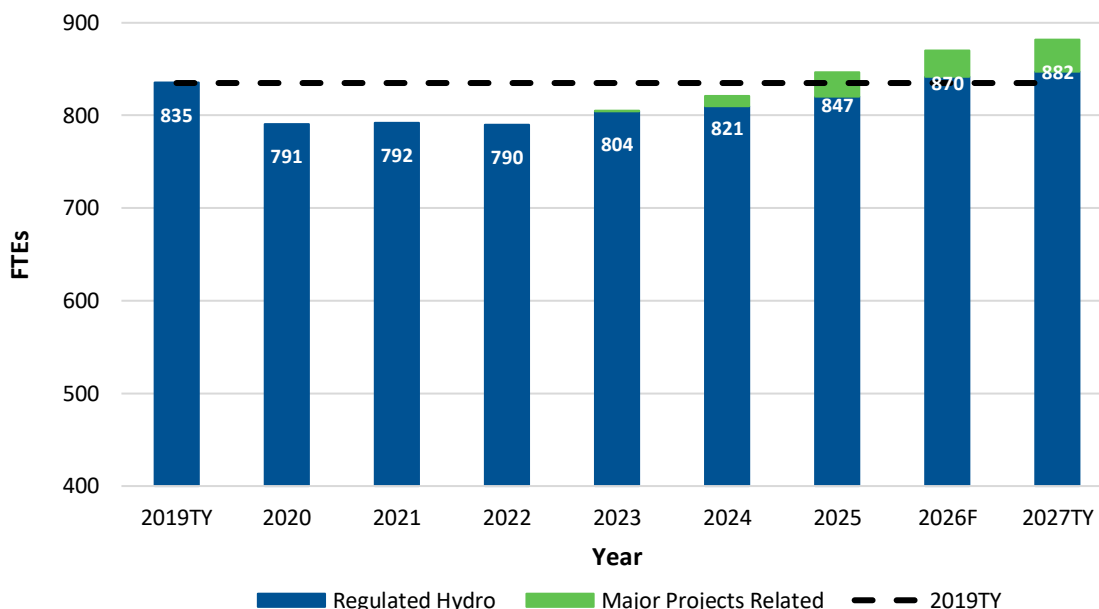


Chart 2-11: Regulated FTEs 2019 Test Year to 2027 Test Year

6 As shown in Chart 2-11, Hydro’s FTEs remained below 2019 Test Year levels during the six-year period
7 between 2019 and 2024.

8 During this period, Hydro’s voluntary attrition peaked at more than double its previous voluntary attrition
9 rates, which had generally been low compared to many industries. In 2023, attrition was higher than
10 historical for several reasons: (i) compensation was the primary issue cited by employees leaving the
11 organization;⁵⁵ (ii) consolidation of positions where prudent as discussed in Section 2.3.1; (iii) broader

⁵⁴ Five additional positions hired in 2025 do not appear in 2026 and 2027 Test Year forecasts as a result of the timing of budget and forecast processes for the 2026 GRA.

⁵⁵ In Hydro’s 2023 employee engagement survey, compensation was the top concern identified by employees. Over 35% of employees surveyed indicated they were either actively pursuing other opportunities or had an intention to leave the organization within two years, with the top cited reason being unfair compensation.

organizational change impacts following restructuring in 2021; and (iv) a competitive labour market.

Through the latter half of 2024, Hydro’s voluntary attrition levels started to settle to levels more in line with Hydro’s historical experience. Hydro monitors its attrition rates as retention of an experienced and knowledgeable workforce is critical, particularly given the monopolistic nature of the utility industry and the associated smaller pool of utility talent, relative to other industries, in Atlantic Canada and beyond.

Attraction and retention of talent continues to be a key organizational risk given the competitive labour market; Electricity Human Resources Canada identified that finding skilled talent is the most pressing constraint for the electricity sector over the next five years.⁵⁶ Through the 2027 Test Year, increases in labour costs are prudent, measured, and reflective of: (i) offering fair compensation and benefits; and (ii) necessary adjustments to Hydro’s workforce requirements. Hydro will manage its labour costs as it appropriately and prudently grows its workforce in preparation to undertake the required major capital investments and support its asset base.

2.3 Managing Costs

While Hydro has undergone material organizational changes since its last GRA, the principles of *Good Utility Practice* and keeping the impact of its costs on customers top of mind have not changed. Hydro’s 2027 Test Year operating costs, when adjusted for inflation,⁵⁷ have decreased by approximately 10% since the 2019 Test Year forecast was established,⁵⁸ which is reflective of Hydro’s prudent cost management.

The costs to serve customers on the Island Interconnected System are materially higher than what is being recovered through the proposed rates within this GRA. The remaining costs are internally funded by Hydro through profits from its overall business activities and other rate mitigation mechanisms. Hydro is accountable to both its customers and, as a Crown utility, to the people of the province. Hydro operates a cost-conscious organization and prudently manages spending organization-wide on both labour and non-labour operating expenditures to ensure it is efficiently managing the costs of both regulated and non-regulated operations. Further information on how Hydro continuously improves its business processes and operations is provided in Section 2.4. Effective cost management across both its regulated and non-

⁵⁶ “Electricity in Demand: Labour Markets Insights 2023–2028,” Electricity Human Resources Canada, <https://ehrc.ca/wp-content/uploads/2024/05/Electricity-in-Demand-Labour-Market-Insights.pdf>.

⁵⁷ Hydro escalated 2019 Test Year non-labour costs using the GDP deflator; 2019 Test Year labour costs have been inflated using historical Stats Canada data and internal labour inflators.

⁵⁸ 2019 Test Year in Real Dollars (\$173.3) - 2027 Test Year in Nominal Dollars (\$156.4) / 2019 Test Year (\$173.3) = 9.8%.

regulated operations supports Hydro's ability to internally fund its rate mitigation requirements in accordance with Governments rate mitigation plan.

A significant portion of Hydro's supply cost is related to the Muskrat Falls Assets. As discussed in Chapter 4, approximately 90% of the Muskrat Falls supply costs are commercially fixed. The approximate 10% remaining are the operationally managed costs, which are determined by Hydro and are primarily operating (labour and non-labour) and sustaining capital costs. These costs are budgeted and incurred by Hydro with the same level of prudence and scrutiny as the regulated operating and capital costs. To ensure transparency for its stakeholders, Hydro provides details in Chapter 4 outlining the breakdown of Muskrat Falls supply costs for the information of the Board and parties in this proceeding.

As shown in Chart 2-12, in the 2027 Test Year, Hydro is forecasting to maintain operating costs below inflation-adjusted 2019 Test Year levels.⁵⁹

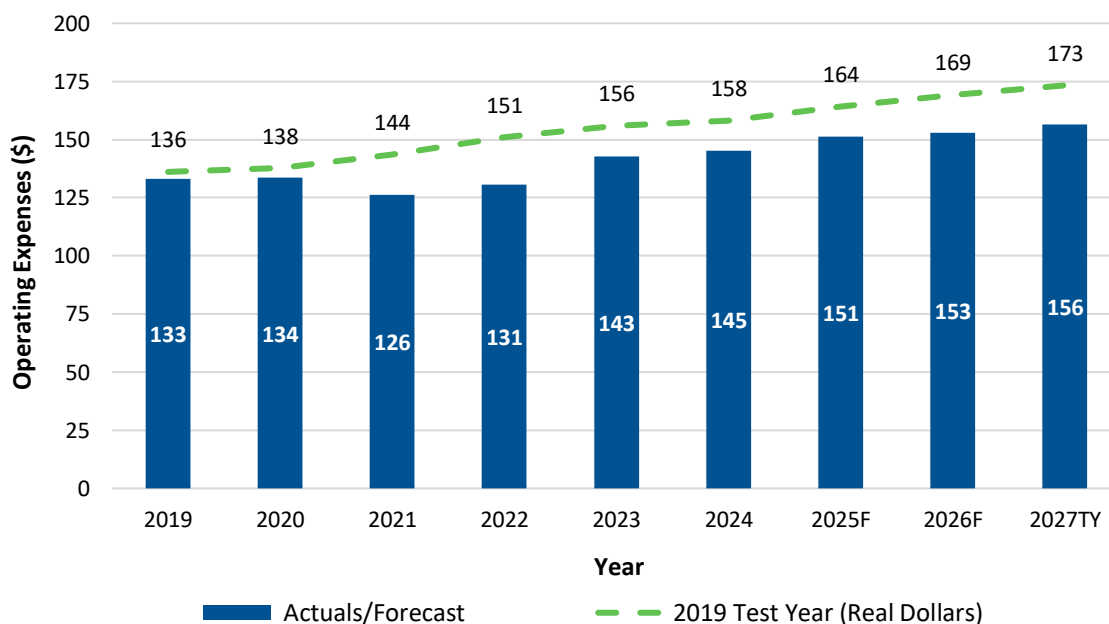


Chart 2-12: Operating Costs (\$ Millions)⁶⁰

⁵⁹ Throughout this application, Hydro has excluded performance contract payments from its 2019 Test Year costs when escalated, as they were disallowed in Board Order No. P.U. 16(2019).

⁶⁰ Throughout this chapter, Hydro's operating costs in 2025F, 2026F and 2027TY are shown net of deferred salaries to the General Expenses Capitalized Deferral Account as approved in Board Order No. P.U. 32(2025).

1 The electricity landscape is characterized by rising costs, aging infrastructure, and evolving customer
2 needs. Recent years have demonstrated upward pressure on operating costs, while the electricity system
3 requires significant expansion. Inflation since the 2019 Test Year has been substantial, with costs
4 escalating by approximately 28% when compounded year over year.⁶¹ A major driver of the inflationary
5 pressure was the COVID-19 global pandemic, whereby the cost of living and consumer pricing escalated
6 dramatically in 2021 and 2022. Cost escalations related to market conditions for materials and equipment
7 pricing, consultant costs, software⁶² and other critical areas are beyond Hydro's control. Where Hydro
8 does have discretion over expenditures, Hydro has focused on prudent cost management throughout the
9 organization. Hydro's operations reflect an appropriate balance between cost management and system
10 reliability for customers. This is evidenced by Hydro's 2027 Test Year operating costs, which have
11 decreased by approximately 10% since the 2019 Test Year, when adjusted for inflation. Hydro's reliability
12 metrics over the same period demonstrate consistent reliability performance. Further, survey results
13 confirm that customers are satisfied with the electricity system's current level of reliability and prefer a
14 cautious approach with respect to additional investment.

15 To enable Hydro to provide reliable, least-cost service to customers in the future, the continued
16 absorption of inflationary costs is not feasible. Prolonged periods of cost and staffing constraints can result
17 in operational risks such that subsequent increases in operating costs are not just required for growth, but
18 to restore sustainable and reliable operations. These pressures, together with customer expectations for
19 affordability and the impact of mitigated rates, require Hydro to be vigilant in the management of its costs
20 and its business, balancing necessary adjustments in operating costs and capital investment.

21 Hydro will undertake necessary growth and capital investment in a measured manner with a focus on
22 meeting its obligations under the *EPCA* to provide equitable access to an adequate supply of reliable,
23 environmentally responsible electricity, at the lowest possible cost to the people of the province.

24 Hydro's proposed 2027 Test Year costs reflect the cost of serving customers within the current operating
25 environment, including significant cost pressures arising from inflation and increasing electricity demand

⁶¹ Weighted inflation rate compounded year over year from 2019 Test Year to 2027 Test Year using GDP deflator (32%) and labour inflation (25%).

⁶² For example, recent trends in IT show that vendors are increasingly exclusively offering cloud-based arrangements, versus legacy on-premises options. Cloud-based software costs can include annual subscription fees for licensing and support that can increase operating costs.

at the provincial, national, and global levels. The costs proposed for the 2027 Test Year are reasonable and prudent and are necessary for Hydro to continue to meet its legislated mandate.

2.3.1 Labour Costs

Consistent with historical trends, approximately 60% of Hydro’s operating costs are related to labour. On a nominal basis, Hydro’s labour cost increase from the 2019 Test Year to the 2027 Test Year is lower than utility industry increases during that same time period. As shown in Chart 2-13, labour costs for the 2027 Test Year are \$9.3 million lower than the 2019 Test Year,⁶³ when escalated at the same rate as increases within the utility industry.⁶⁴

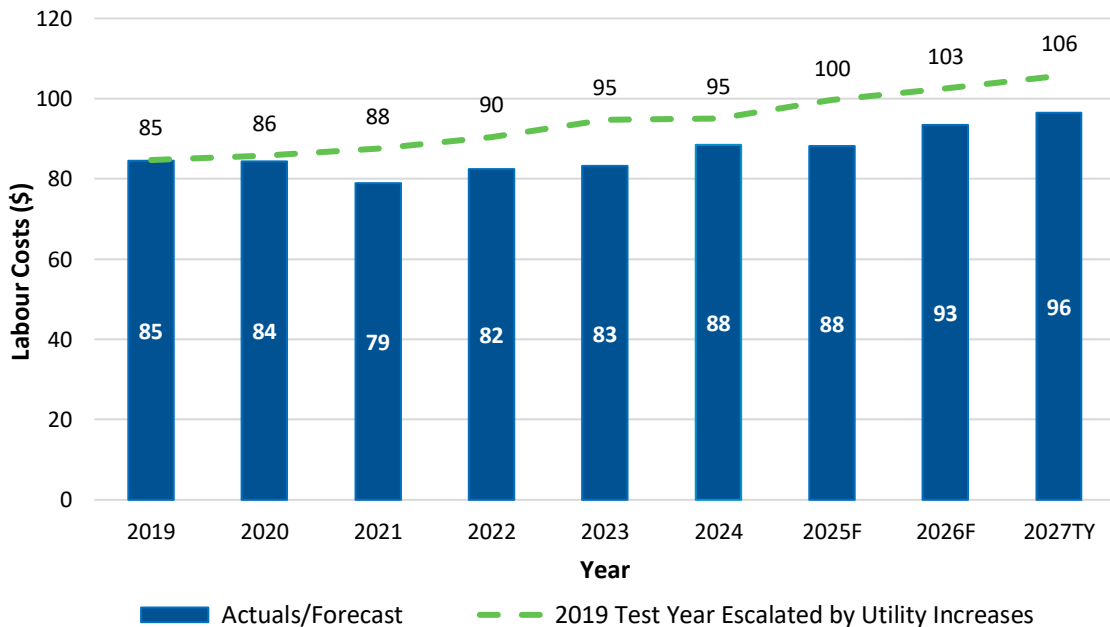


Chart 2-13: Labour Costs vs Inflation (\$ Millions)

Within its labour costs, Hydro has largely absorbed inflation since 2019 as a result of a reduction in FTEs and an extended salary freeze, both of which are unsustainable actions for Hydro’s near and long-term operations. Hydro pursued operating cost reductions as ordered by the Board in the 2013 and 2017 GRAs,

⁶³ 2019 Test Year Labour Costs in Real Dollars (\$105.7) – 2027 Test Year Labour Costs (\$96.4) = \$9.3. Numbers may not add due to rounding.

⁶⁴ 2019 Test Year labour costs are inflated through 2025 based on rates per Statistics Canada's Average Weekly Earnings for Electric Power Generation, Transmission and Distribution Industries, Canada, All Employees, Excluding Overtime (Table 14-10-0203-01). Average weekly earnings by industry, monthly, unadjusted for seasonality). The 2019 Test Year labour costs are escalated consistent with internal labour inflation rates for 2026F and 2027 Test Year.

as well as the Board’s 2020 recommendation that Nalcor and Hydro undertake a comprehensive organizational review to identify \$20 million in savings from the overall organization, as outlined in the final report of the *Rate Mitigation Options and Impacts Review* proceeding.⁶⁵ As a result, Hydro conducted FTE reviews, including the prudent consolidation of positions and elimination of redundancies, where possible.

Between the 2019 Test Year and 2022, Hydro reduced its FTEs primarily through retirement and voluntary attrition, resulting in a reduction in labour costs. Hydro worked to ensure every opportunity to reduce labour costs was considered, while also balancing the risks of additional operational responsibility on remaining staff. Ultimately, as discussed in Section 2.2.4, in conjunction with salary freezes during the period, there was a negative impact on attrition rates. With a competitive and shrinking labour market and significant major capital investments required to support system reliability, enable the retirement of aging assets and prepare for pending load growth,⁶⁶ staffing constraints that had been in place through 2022 are not sustainable over the near and long term.

Following this period of right-sizing the organization, Hydro began to increase its staffing levels in 2023 to be ready to prudently plan for and execute new system additions, and labour costs reflect this increase. The primary drivers of Hydro’s increase in labour cost in the 2027 Test Year include forecasted salary and benefits adjustments aligned with market indicators and an increase in FTEs between the 2019 and the 2027 Test Years.

2.3.2 Non-Labour Costs

Inflationary impacts on non-labour costs have also been significant since Hydro’s last GRA, resulting in increased pressure across all of Hydro’s operating segments. These costs, including professional services, materials, contract labour and other maintenance-related expenses, are necessary to operate Hydro’s assets in accordance with *Good Utility Practice*. Despite broad upward pressure on operating costs, non-labour costs in the 2027 Test Year are below the 2019 Test Year levels when adjusted for inflation, which demonstrates sustained progress in cost management and operational efficiency. Performance versus

⁶⁵ “Rate Mitigation Options and Impacts Muskrat Falls Project – Final Report,” Board of Commissioners of Public Utilities, February 7, 2020.

⁶⁶ “2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study,” Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).

- 1 inflation reflects Hydro’s commitment to continuous improvement and delivers tangible benefits for
- 2 customers.
- 3 As illustrated in Chart 2-14, Hydro’s actual and forecasted non-labour costs through the 2027 Test Year
- 4 remain consistently below the inflation-adjusted 2019 Test Year levels.

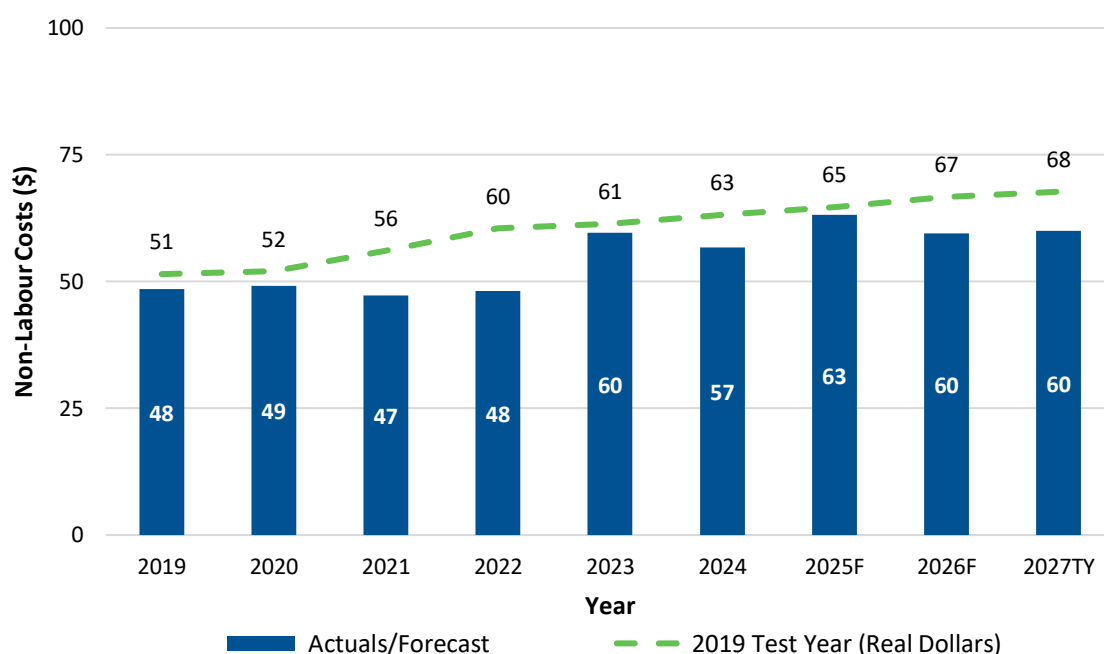


Chart 2-14: Non-Labour Costs vs Inflation (\$ Millions)⁶⁷

- 5 Despite significant inflationary pressures, the 2027 Test Year forecast reflects the avoidance of
- 6 incremental operating expenditures as a result of continued prudent cost management and operational
- 7 efficiency. Overall, Hydro is forecasting reductions totalling approximately \$8 million, or approximately
- 8 13%⁶⁸ in the 2027 Test Year, relative to the 2019 Test Year, when adjusted for inflation, underscoring
- 9 Hydro’s efforts to mitigate the impact of externally driven cost increases. This includes the \$4 million
- 10 productivity allowance discussed later in Section 2.4.6. Chart 2-14 demonstrates Hydro’s ability to manage
- 11 non-labour expenses effectively; however, consistently absorbing inflation is unsustainable in parallel with
- 12 preparation for system growth and the investments required to maintain system reliability.

⁶⁷ Non-labour costs, including SEM, other, and cost allocations (recoveries).

⁶⁸ 2027 Test Year Forecast in Real Dollars (\$67.6) - 2027 Test Year Forecast in Nominal Dollars (\$59.9) / 2027 Test Year Forecast (\$59.9) = 12.8%.

Growth in electrification nationally and globally has increased pressure not only on the labour market, but also on supply chains and material costs. The prices of goods and services that make up the majority of Hydro's non-labour costs are largely market-driven and provided by third parties and thus are outside of Hydro's direct control. Hydro must procure many of these inputs to maintain the safe and reliable operation of the electricity system. For example, when a motorized valve requires replacement, Hydro must procure the equipment at prevailing market prices, as maintaining and operating the electrical system and ensuring a reliable supply of electricity are part of Hydro's legislated mandate. Contractor and consultant labour costs are also escalating due to market pressure and increased competition for resources in the labour market. All of these factors limit opportunities to offset costs without increasing Hydro's operational risk.

2.3.3 Conservation and Demand Management

CDM programming undertaken by Hydro serves to reduce system costs while delivering customer bill savings. Hydro's CDM programming includes joint utility programs offered by both Hydro and Newfoundland Power on the Island and Labrador Interconnected systems, as well as its Industrial and Isolated system programming, which is offered solely by Hydro.

In 2025, Hydro's residential, commercial, and industrial CDM programs yielded a total of 1,742 MWh of annual incremental energy savings.⁶⁹ Chart 2-15 shows cumulative energy savings achieved through CDM programming from its implementation in 2019 through 2025.

⁶⁹ In 2025, no industrial energy efficiency projects were completed; however, Hydro's Key Accounts Specialist remains engaged with Industrial customers to assist with future projects, should customers want to pursue them.

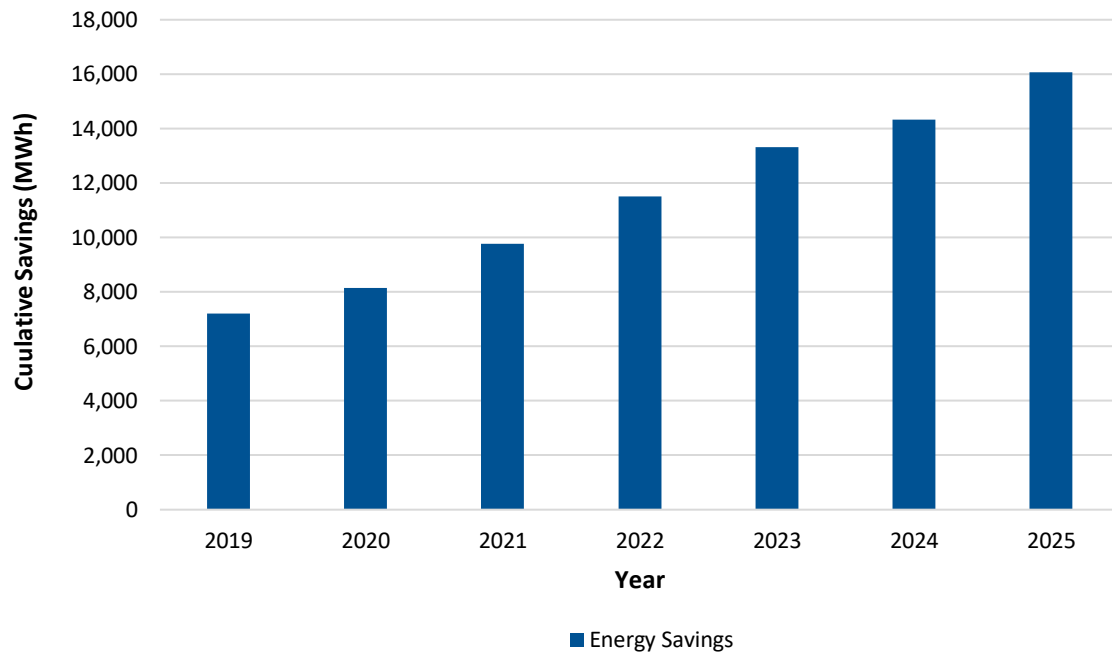


Chart 2-15: Cumulative CDM Energy Savings 2019–2025 (MWh)

1 As of the end of 2025, Hydro has achieved total cumulative energy savings of 16,067 MWh since its last
2 GRA in 2019 – enough to serve the communities of both Nain and Mary’s Harbour for a full year. CDM
3 energy savings are achieved over many years, as savings continue to occur each year for the life of the
4 installed measures.

5 The suite of CDM programming offered to customers is determined by the utilities, and cost-effectiveness
6 is tested on an individual basis for Hydro for Industrial customers and on its Isolated systems and on a
7 combined basis with Newfoundland Power’s customers on interconnected systems. As approved by the
8 Board in Order No. P.U. 18(2016), the cost-effectiveness of CDM programming is determined using the
9 Total Resource Cost and Program Administrator Cost tests. These tests are a benefit-to-cost ratio where a
10 result of 1.0 or greater indicates that a program is cost-effective. When tested, results for the suite of
11 CDM programming offered to customers confirm that the benefits provided to customers outweigh the
12 costs incurred.

Since 2019, Hydro has incurred \$9.1 million in costs to deliver CDM initiatives to achieve its 16,067 MWh in cumulative energy savings. Table 2-2 provides the estimated costs of delivering customer CDM programs from 2019 through the 2027 Test Year.⁷⁰

Table 2-2: Customer CDM Costs (\$000)

	2019	2020	2021	2022	2023	2024	2025	2026F	2027TY
CDM Costs	2,084	826	1,754	1,356	1,628	1,661	1,564	2,040	2,547

Hydro evolves its programming to meet customer needs, drive system benefits, and respond to changes in technology while taking advantage of external funding opportunities. Some examples of recent developments in its CDM portfolio include:

- **CDM Potential Study** – A new joint potential study completed with Newfoundland Power, which will inform the next five years of CDM programming on the Island Interconnected System.
- **Isolated Marginal Cost Study** – Hydro has engaged Dunskey to prepare a marginal cost study for its Isolated systems for both capacity and energy. This study is ongoing and will help inform CDM activities in isolated communities and ensure Hydro is appropriately valuing the cost of capacity on its Isolated system as it identifies opportunities for savings.
- **Green Industrial Facilities Manufacturing Program** – In 2025, Hydro received \$2.7 million in funding from Natural Resources Canada under the Green Industrial Facilities Manufacturing Program. Hydro is using these funds to undertake strategic energy management, energy audits and capital upgrades to fish plants located in isolated communities.
- **Canada Greener Homes Affordability Program** – Hydro, in partnership with Newfoundland Power, has submitted an application to be the provincial delivery partner of Canada Greener Homes Affordability Program in Newfoundland and Labrador. If successful, this application will allow for increased levels of CDM programming for income-qualified customers in the province, with specific programming for both the Interconnected and Isolated systems.
- **Alternative Space Heating Pilots** – Hydro has been exploring ways to promote alternatives to electric space heating in isolated communities as a means to reduce the costs associated with the

⁷⁰ Includes CDM only and excludes costs related to the delivery of electrification initiatives and programming.

Rural Deficit, promote energy security, and reduce emissions from diesel generation. Work has been undertaken to pilot both biomass (wood) and solar-powered heat pumps.

2.3.4 Rural Deficit

In accordance with the *EPCA*, all consumers in the province are required to have equitable access to an adequate supply of power. Hydro therefore has a statutory obligation to reliably serve all customers within its service areas and is taking prudent steps to manage the costs of providing services to Rural customers.

Hydro provides electrical service to approximately 27,900 Rural customers on its Interconnected and Isolated Diesel systems, to which rates charged do not reflect the full cost of service, consistent with Government direction.^{71,72,73} The shortfall between the cost of serving these customers and the revenue collected is referred to as the “Rural Deficit.” Table 2-3 outlines the Rural Deficit for the 2019 and 2027 Test Years.

Table 2-3: 2027 Test Year Rural Deficit (\$ Millions)

	2019 Test Year	2027 Test Year
Rural Deficit	64.3	65.0

The Rural Deficit remained consistent in the 2027 Test Year when compared to the 2019 Test Year. Costs increased by \$0.7 million over the 2019 Test Year, primarily due to rate mitigation reducing costs on the Island Interconnected System and improved revenue to cost coverage on Island Interconnected, Island Isolated and Labrador Isolated systems. With the commissioning of the Muskrat Falls Assets, Hydro’s Rural customers on the Island Interconnected System are now subject to higher costs of supply.⁷⁴ The Rural Deficit is approximately 8% of Hydro’s overall revenue requirement.⁷⁵

⁷¹ In the 1970s, Government established several policies which discouraged rate differentials throughout the province, one of which directed that electricity rates charged to rural areas conform to those rates approved for Newfoundland Power customers. Formal direction is included in Government of Newfoundland and Labrador, *Order in Council OC2003-347*, July 8, 2003.

⁷² The Rural Deficit excludes Government departments, which pay full cost rates as approved by the Board.

⁷³ Hydro serves approximately 11,700 Rural customers on the Labrador Interconnected System, whose rates recover the cost to serve as well as a contribution to funding a portion of the Rural Deficit.

⁷⁴ Further information on Hydro’s 2027 Test Year revenue requirement and cost to supply is included in Chapter 5.

⁷⁵ 2027 Test Year Rural Deficit (\$65.0) / Hydro’s 2027 Test Year Revenue Requirement (\$797.7) = 8.1%.

The Rural Deficit is funded through the rates paid by Hydro’s Utility customer, Newfoundland Power, and Hydro’s customers on the Labrador Interconnected System. The portion funded by each customer group is determined through test year cost of service studies filed as part of Hydro’s GRAs.⁷⁶ In accordance with the 2019 Test Year Cost of Service Study approved by the Board, the current allocation is 96.1% for Newfoundland Power and 3.9% for customers on the Hydro Rural Labrador Interconnected System. The proposed allocation in this application is 96.6% for Newfoundland Power and 3.4% for Rural Labrador Interconnected customers, as outlined in more detail within Schedule F.

In the context of Government’s direction on Rural customer rates, Hydro actively works to keep the Rural Deficit as low as possible. To that end, Hydro files an annual report providing an overview of the Rural Deficit, which identifies the direct operating and capital initiatives undertaken by Hydro to manage costs associated with serving customers in rural areas. Hydro has undertaken a variety of initiatives to support its management of the Rural Deficit, including:⁷⁷

- Engagement in Cost-Effective Renewable PPAs, which allow Hydro to serve customers in Isolated systems at a lower cost than diesel and in a more environmentally responsible manner.
- Support of the Nunatsiavut Government and their development partner, Natural Forces, in advancing the Nain Wind Microgrid project.
- Focus on cost-effective CDM in isolated communities and leverage external funding, such as the Green Industrial Facilities Manufacturing Program, where possible.⁷⁸
- Pursuit of opportunities for increased use of biomass space heating in isolated communities.
- Participating in Load Growth Working Group meetings with the Nunatsiavut Government.
- Identifying and implementing opportunities to lower its operating costs in Isolated systems.

There are challenges associated with the Rural Deficit, which are a result of community factors beyond Hydro’s control: community population changes, relocations, electrification trends, and abandonment of services provided by a third party, all of which impact the Rural Deficit. Like the Island Interconnected

⁷⁶ Consistent with s. 3(a)(iv) of the *EPCA*, Island Industrial Customers do not contribute towards the cost of the Rural Deficit.

⁷⁷ Savings achieved through these initiatives are primarily through avoided costs or productivity improvements; therefore, Hydro is not able to quantify the exact impact on the Rural Deficit.

⁷⁸ Hydro secured funding from the Green Industrial Facilities Manufacturing Program to undertake strategic energy management, energy audits and capital upgrades to fish plants located in isolated communities, which reduce electricity use and therefore use less fuel. For additional information on Hydro’s CDM activities, please refer to Section 2.3.3.

System, certain isolated communities are experiencing load growth and require increasing levels of capital investment to meet customer requirements for reliable service, which is Hydro’s legislative obligation to provide. Some customers are increasingly seeking to install electric space heating in isolated communities, such as the Department of Health and Social Development building in Rigolet.⁷⁹ Conversely, since 2017, three communities within Hydro’s system have been relocated.⁸⁰ Community relocations create the risk of stranded assets for Hydro.

Hydro is experiencing challenges associated with third parties abandoning services in Isolated system communities, such as the condemned wharf in McCallum, and challenges in maintaining heating oil delivery in St. Brendan’s. Such events are driving increased capital costs and/or increased risk of electricity consumption due to uncertainty around heating fuels. Both planned and unplanned electrification is expected to occur on Hydro’s Isolated systems in the coming years, which will impact the Rural Deficit.⁸¹

2.4 Continuous Improvement

Since Hydro’s last GRA, Hydro has focused on evolving its business to achieve long-term, sustainable cost savings and productivity gains. Hydro’s progress is reflected in its performance versus inflation relative to the 2019 Test Year, as well as other qualitative changes or improvements and broader business performance.

Given the rate pressures faced by customers, Hydro balances cost impact with necessary investment and expenditures in recognition of the contributions that are necessary for rate mitigation. As outlined in Section 2.2, Hydro optimizes its overall organizational performance by:

- Identifying opportunities to economically manage its system operations;
- Utilize long-term capital investment strategies to maximize asset life; and
- Maximizing returns for customers using export and import opportunities.

⁷⁹ Hydro’s capital expenditures of approximately \$3.4 million for Rigolet were approved in Board Order No. P.U. 25(2024).

⁸⁰ Since 2000, eight communities have relocated—Great Harbour Deep (2002), Petites (2003), Big Brook (2004), Grand Bruit (2010), Round Harbour (2016), William’s Harbour (2017), Snook’s Arm (2018) and Little Bay Islands (2019).

⁸¹ In Board Order No. P.U. 25(2024), the Board acknowledged a potential issue relating to load growth and increased supply costs from electrification, such as through electric heating systems in isolated communities, and the resulting impact on Newfoundland and Power customers through the Rural Deficit. The Board requested that Hydro provide a proposed strategic load management plan for Isolated systems, which would include an assessment of Hydro’s load management approach on Isolated Diesel systems, objectives of the plan and the planned implementation/execution approach. Hydro’s report is due on November 30, 2026.

Hydro also focuses on workforce management, contracting and procurement, work planning and execution, capital planning, and technology to advance continuous improvement and efficiencies in its business. Such efforts do not necessarily result in year-over-year reductions to operating expenditures; rather, they act to moderate and avoid what would otherwise be higher operating costs across the business.

While Hydro has mitigated inflationary pressures, it is not feasible to continuously absorb these pressures without impacting Hydro's ability to reliably deliver service. Looking forward, Hydro will continue to evolve its operations and implement productivity and operational efficiencies to improve the management of its operating costs and reduce them where prudent. Operational efficiencies may serve to offset upward cost pressures rather than generate standalone savings. These ongoing efforts demonstrate Hydro's commitment to effective cost management while maintaining its core service and operational responsibilities.

2.4.1 Workforce Management

Since its last GRA, Hydro has unified its human resources function to support centralized oversight of the management of its labour resources and labour-related costs. Examples of practices that have evolved include FTE management, hiring sessions, data analytics, and budgeting processes related to training and development. Hydro has also enhanced its analysis of labour-related data to understand labour trends, inform decision-making and support management of labour costs organization-wide. For example, electronic dashboards have been implemented for the management and monitoring of overtime, providing a comprehensive view of operational requirements, areas requiring additional effort, and performance against labour budgets. This supports cost management, workforce planning efforts, and safety and health priorities. Employee self-service was introduced in 2020, which enabled electronic paystubs and T4 statements, and self-service options including personal information updates. Hydro is also utilizing online training platforms to deliver commonly used training courses, resulting in increased availability of training and efficiency of delivery.

Hydro's approach to workforce management ensures that labour cost decisions on both the regulated and non-regulated sides of the business are made with customers' best interests in mind.

Shared Service Model

Following the restructuring of the organization in 2021, Hydro further consolidated its corporate services by function, providing support across all areas of the business. This alignment avoids duplication of function, thus better managing costs, and provides subject matter expertise across the organization in line with Hydro's functional organization design. The costs associated with these functions are allocated through the Intercompany Guidelines, consistent with the approach outlined in Hydro's 2017 GRA. This approach enables Hydro's regulated business segment to avail of economies of scale and reduces costs for its customers by incurring only a portion of the overall cost of the delivery of corporate services through administration fees. Costs are defined and allocated for both the regulated and non-regulated operations to ensure that customers are paying only those costs related to providing regulated service.

Hydro's Intercompany Guidelines were last reviewed in detail during Hydro's 2013 GRA. At that time, the allocation methods for common services were reviewed by the Board's Expert, Mr. Brad Rolph from Grant Thornton, and Nalcor's expert, Deloitte, who all found the methods reasonable.⁸² The Intercompany Guidelines were updated in 2026 and reviewed by KPMG, a third-party expert, who determined them to be reasonable. The Intercompany Guidelines and the KPMG report are provided as Exhibit 2.⁸³

Given that Hydro's customers ultimately pay for the allocation of shared service costs to Hydro's regulated operations and the allocation to the Lower Churchill Companies,⁸⁴ the efficiencies resulting from shared services for the entire organizational structure provide a lower overall cost for customers. For example, if Hydro and the Lower Churchill Companies each had to acquire and implement their own Accounts Payable system, the duplication of effort would result in higher costs to Hydro's customers than participation in a shared services approach. If Hydro had pursued a standalone Accounts Payable system for its regulated operations, customers would have paid for the whole of that cost, in addition to a larger percentage allocation of a separate Accounts Payable system for the Lower Churchill Companies because of that cost being allocated between fewer entities.⁸⁵

⁸² Board Order No. P.U. 49(2016), pp. 37–38/45–1.

⁸³ The Intercompany Guidelines and the KPMG report are provided as Attachments 1 and 2, respectively, to Exhibit 2.

⁸⁴ Lower Churchill Companies operate the Muskrat Falls Assets.

⁸⁵ In accordance with OC2013-343, Hydro is required to pay all costs related to the Lower Churchill Project. Therefore, subject to rate-mitigation impacts, costs such as Accounts Payable will be allocated to affiliates for recovery through the Muskrat Falls PPA, and the Transmission Funding Agreement will be included in the charges paid by Hydro's Island Interconnected Customers.

In Board Order No. P.U. 27(2022),⁸⁶ the Board stated it was “. . . of the view that the shared-services approach is preferable to a stand-alone model, considering the sharing of information required in the context of the corporate structure of Nalcor and Hydro.”

2.4.2 Contracting and Procurement

Hydro continues to pursue opportunities to minimize risk and realize efficiencies in its contracting and procurement efforts, with the goal of obtaining the greatest value for the benefit of customers.

By leveraging economies of scale, Hydro explored joint and/or bulk procurement opportunities with external bodies, both public and private, to achieve real cost savings for customers. Examples include:

- Participating with Government in an Atlantic Canadian consortium to secure better rebates and interest rates on purchasing cards.
- Utilizing a centralized business account with wholesalers such as Amazon, Hydro has realized cost savings through discounts, rebates and reduced shipping costs.
- Partnering with the federal government to leverage better rates and contractual terms on security contracts for Hydro facilities.
- Participating in a strategic purchasing initiative for Managed Print Services led by the Newfoundland and Labrador Public Procurement Agency, resulting in lower costs on device acquisition, supplies, and service agreements.
- Partnering with Government and other entities to leverage better rates and contractual terms for general procurement and fleet management activities.

Technology options which have the capability to perform improved reporting in spending, contract and supplier management have been introduced as a means of better informing future decision-making and supporting Hydro’s least-cost mandate. As an example, the implementation of an Online Requisition system in 2020 has moved the procurement approval process from a paper-based to an electronic process, thus mitigating risk and increasing efficiency within the procure-to-pay process. Further, transition to the use of a mobile application for the approval of procurement card expenses reduces administrative overhead costs, enables increased efficiency in processing statements and allows for better

⁸⁶ Issued in relation to “Business Systems Transformation Program Application,” Newfoundland and Labrador Hydro, May 25, 2022.

document management and alignment with Hydro’s financial, auditing and information management requirements related to purchasing cards.

In addition, Hydro is implementing strategic procurement initiatives, such as the inclusion of early execution scopes within its Major Projects applications. Approval of early execution applications enables Hydro to secure equipment at current prices and production slots for equipment years in advance, mitigating cost and schedule risks to projects while the regulatory process proceeds, which could otherwise result in millions of dollars in project delays and cost increases to customers. Further information on strategic procurement efforts is found in Section 2.4.6.

2.4.3 Work Planning and Execution

Since the last GRA, Hydro has continuously improved in this area primarily through: (i) integration of work planning and execution activities, including outage management; (ii) improved coordination and scheduling of work; and (iii) review, modification, and strengthening of processes, and software.

Hydro is working toward the optimization of shutdown and major equipment outages, particularly those that require cross-departmental collaboration. Hydro’s integrated outage management approach strives to support execution of capital projects and maintenance work across the system. For example, Hydro has been working to reduce the number of annual outages in Labrador West through collaborative efforts from regulated and non-regulated business segments. In 2026, line crews from across the organization worked together to perform live line activities by removing energized conductors to electrically isolate a disconnect that is scheduled for replacement. As a result, Hydro has reduced customer impact in Labrador West and has potentially eliminated one outage in 2026.

From a software standpoint, Hydro implemented enhancements within its Enterprise Resource Planning system, with the goal of improved coordination of work as follows:

- Improved clustering of work packages based on geographical areas, common equipment condition requirements, and labour plans, to optimize crew utilization and equipment availability;
- Auto-scheduling feature within the module eliminates the manual effort required to pull work orders from the system and enables recognition of work backlog or carryover; and
- Rationale and tracking of work order schedule completions, which allows Hydro to identify trends, risks, and opportunities for planning and scheduling optimization.

Further, Hydro is currently undertaking a pilot project in Bay d’Espoir, which is focused on data cleansing and optimizing its current software to build a stronger asset management foundation. This initial phase is crucial for data quality and accuracy within the asset information system. Improvements in asset information drive more effective management of preventative maintenance and corrective maintenance within work execution. Once fully operational in Bay d’Espoir, Hydro plans to apply the same approach to the remaining hydraulic generation assets. Lessons learned and advancements gained in hydraulic generation will inform the development of consistent and common practices in other regulated areas such as transmission and distribution, terminal stations, and CTs.

Efforts are underway to improve Hydro’s work planning and execution are focused on making foundational improvements that have a sustainable impact on the way Hydro manages its assets and determines the priority of future capital investment. Although these activities do not necessarily result in direct or immediately quantifiable reductions in operating expenditures, they deliver operational efficiencies that improve productivity, reduce customer impacts, and enhance system reliability. Improved planning and execution mitigate upward cost pressures that would otherwise be reflected in higher operating, supply or capital costs.

2.4.4 Capital Planning

Hydro’s capital investment approach is to invest a level of capital expenditure that appropriately balances reliability with cost management, considers the rate pressures facing customers, and is founded in evidence-based decision-making informed by external stakeholder input.

From 2019 through 2024, Hydro’s regulated business segment has maintained capital investment at levels below its ten-year historical average. When considered alongside Hydro’s reliability performance, Hydro has achieved a reasonable balance of maintaining customer reliability and least cost. Excluding Major Projects, capital expenditures through the 2027 Test Year remain in line with the historical average from the last decade.

Since its last GRA, Hydro has further focused its capital portfolio planning process to ensure that capital investment reflects condition-based assessments (versus age or interval-based), where possible. Changes are ongoing to improve processes around Hydro’s five-year capital spending plan, such that cost savings are identified, where appropriate, as well as efficiency in the planning and execution of capital. A recent example included the optimization of the Unit 7 life extension outage by including additional work scope

that would have required another unit overhaul, avoiding \$5.0 million in costs to dismantle the unit a second time.

Hydro is working to improve its capital estimates. For example, for projects included in the 2025 Build Application, Hydro has improved cost estimating by performing constructability review, utilizing the AACE guidelines for estimate accuracy, including maturity matrices, and performing quantitative risk analysis for project budget development. Hydro is adding construction planning expertise within its engineering teams to improve project execution. In its 2026 CBA, Hydro changed the pacing of some of its capital programs in response to market conditions, such as supply chain constraints and labour availability, to reduce carryover and improve capital work execution.

Hydro carefully reviews its capital portfolio each year to ensure proposed applications include only those programs and projects that are most critical to system operations. As part of its preparation for the 2026 CBA, Hydro reduced its planned 2026 work scope by \$18.5 million.⁸⁷

Hydro's capital expenditures trend is shown in Chart 2-16.

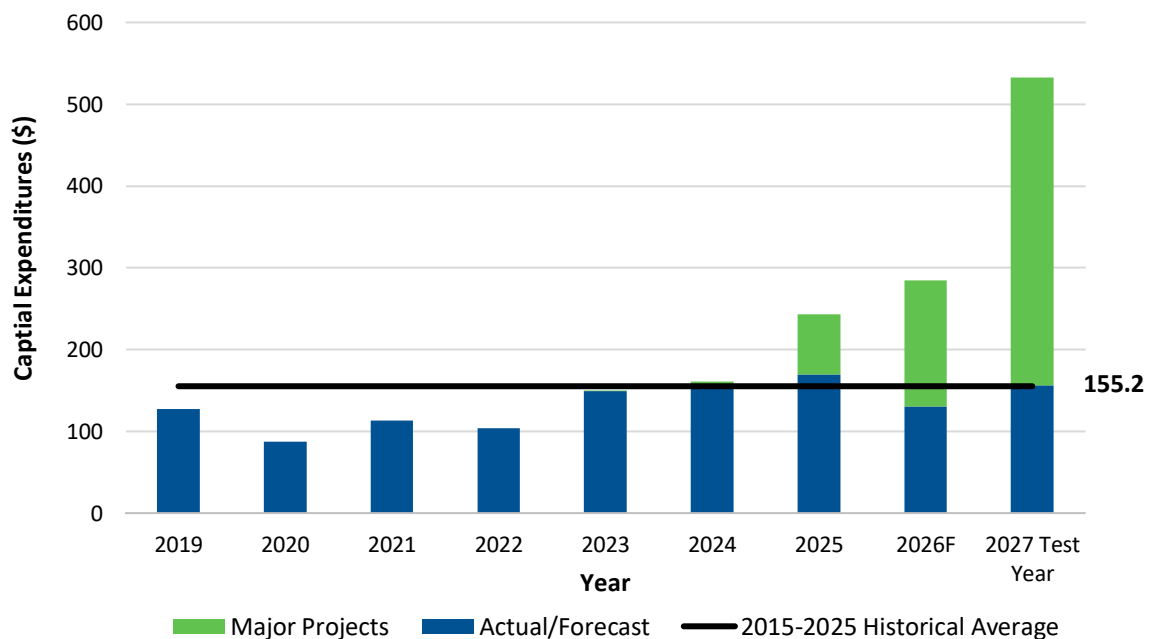


Chart 2-16: Historical, Actual and Forecasted Regulated Capital Expenditures (\$ Millions)

⁸⁷ \$18.5 million was derived from Class 5 estimates, and the true amount of deferred investment is likely higher.

Sustaining capital costs associated with the Muskrat Falls Assets are budgeted by Hydro with the same level of prudence and scrutiny as the regulated capital costs and are required to operate and maintain the assets and to preserve system reliability and safety. More information on sustaining capital costs is provided in Chapter 4.

Looking ahead, in order to meet Hydro's legislative obligation to provide adequate supply and electricity service to customers, there is a need to increase capital investment through Major Projects and to sustain reliability of existing assets over the next five years. Inaction and failing to advance solutions to maintain system reliability and retire aging assets present significant risks; however, overbuilding risks burden ratepayers with unnecessary costs. To mitigate that risk, Hydro is moving forward with only those projects that are absolutely and urgently required to support system reliability and have supply in place to meet future load growth. While increased capital investment is prudent and required, Hydro endeavours to minimize the associated impacts on customer rates and revenue requirements.

2.4.5 Other Technology Advancements

Leveraging the use of technology within the organization supports all aspects of Hydro's business, mitigates operational risk, and enables the productivity of Hydro's workforce in several key areas:

- Enabling remote work execution;
- Utilizing data analytics and improving data accessibility to support decision-making;
- Inspecting and reporting on asset condition;
- Increasing field-accessible technologies;
- Modernizing legacy technologies; and
- Streamlining manual processes.

Remote Work Execution

Hydro has expanded the use of secure remote access and web conferencing to support work mobility, enabling employees to access corporate systems and collaborate effectively from any location. Hydro has made advancements in remote access technology so that staff are able to remotely operate and adjust outputs, survey and address alarms, and troubleshoot equipment issues. For example, personnel can remotely access HVDC and diesel generation assets in Labrador, providing immediate troubleshooting

1 assistance instead of having to travel to the site. These technologies enable increased response time for
2 customers, allow for earlier identification and escalation of issues to improve operational outcomes,
3 reduce the duration of outages, if applicable, and avoid travel, fuel and labour costs. Additional remote
4 technologies are also being explored for future use, including a pilot program for the delivery of remote
5 support through virtual reality.

6 Hydro's ability to execute its operations remotely, both at the field and corporate levels, is a key element
7 to ensuring business continuity in times of system events, such as wildfires. In addition, these capabilities
8 reduce the likelihood of cost escalation by enabling earlier intervention before conditions potentially
9 deteriorate into more significant equipment failures requiring emergency response or replacement.
10 Improved remote coordination and system visibility also reduce inefficiencies in workforce deployment
11 during system events, limiting incremental overtime and mobilization costs and enhancing overall
12 operational efficiency.

13 ***Data Analytics***

14 Hydro is piloting the use of enterprise data analytics tools, including Power BI, across three business areas
15 to improve operational visibility and support informed decision-making. Data analytics software is used to
16 improve the interrogability of Hydro's data and act as a bridge between systems that are not currently
17 integrated. These pilot initiatives are focused on enhancing reporting, operational insights, and business
18 analysis capabilities while improving Hydro's ability to analyze trends, monitor performance, optimize
19 resource utilization, and identify emerging risks and opportunities.

20 The organization is also developing a formal Data Governance model to strengthen data quality,
21 consistency, stewardship, security, and protection across enterprise systems. This work supports improved
22 confidence in business information, establishes clearer accountability for data management, and enhances
23 Hydro's ability to leverage data effectively while protecting sensitive and operationally critical information.
24 This is anticipated to result in avoided costs by reducing unplanned outages and emergency repairs,
25 deferring or optimizing capital expenditures, minimizing inefficient resource allocation, and mitigating the
26 risk of cost escalation.

27 ***Asset Inspection Technologies***

28 Hydro has implemented new technologies within the field that enable asset inspections to inform
29 condition reporting at a lower cost while also reducing safety risks. Autonomous and remotely piloted

1 technology can perform certain asset inspections and assessments that historically required specialized
2 personnel to execute, mitigating the cost and availability of skilled labour and contractors in a competitive
3 market. Technologies like remote operated vehicles and unmanned aerial vehicles limit personnel
4 exposure hours, which improves safety outcomes and increases Hydro's ability to conduct inspections
5 during challenging conditions, such as frazil ice events.

6 The use of autonomous and remotely piloted technologies results in avoided costs by reducing reliance on
7 specialized personnel and external contractors, as well as associated travel and mobilization expenses.
8 When conducted on a timely basis, condition assessments enable proactive maintenance, avoiding higher-
9 cost emergency repairs, unplanned outages, and accelerated asset deterioration.

10 ***Increasing Field Accessibility***

11 Hydro has been leveraging technology, such as Starlink, to increase the availability of technology in the
12 field. In addition, increasing mobile accessibility to core safety programming and administrative tasks, such
13 as timesheet approval, has enabled supervision and field crews to increase hands-on operational time in
14 the field, and reduced paper-based, manual processes through digitization and automation.

15 In 2026, Hydro is implementing electronic tailboards⁸⁸ within its field operations. This is consistent with
16 many other utilities across Canada, enabling Hydro to maintain compliance with legislative safety
17 requirements and reducing the manual, paper-based process previously required of field supervision. The
18 implementation of this technology enables field supervision to improve field level hazard identification,
19 resulting in improved safety and operational outcomes.

20 Increased use of technologies by field personnel increases hands-on operational time and reduces
21 administration time. These improvements reduce rework, minimize the risk of errors and non-compliance
22 with legislative safety requirements, lower the likelihood of corrective actions, and avoid the costs
23 associated with the additional effort.

24 ***Modernizing Legacy Technologies***

25 From an IT perspective, Hydro has worked to modernize and update some of its aging IT infrastructure,
26 which enables efficiencies, avoids increased costs associated with maintaining outdated technology and

⁸⁸ A safety tailboard is a short pre-work briefing held at a job site to identify potential hazards and establish safety procedures before starting work.

1 can result in efficiencies and cost savings within the business that previous dated technologies did not
2 allow.

3 The implementation of Microsoft 365 resulted in a wider range of platform capabilities, including
4 collaborative workspaces, workflow automation, low-code applications, business intelligence, and
5 scheduling tools. Some of these tools include SharePoint, Teams, OneDrive and Power BI, all of which are
6 in various stages of deployment. One example of cost savings achieved by the implementation of more
7 modern technology is the discontinuation of Hydro's contract for independent virtual meeting technology
8 as a result of the adoption of Microsoft Teams through Hydro's Email Migration project.⁸⁹

9 Another example of operational efficiency from modernizing legacy systems is the integration of
10 Geographic Information System⁹⁰ technologies into a consolidated enterprise platform. The platform
11 improves data consistency, accessibility, and operational visibility across the organization. Consolidation of
12 Geographic Information System technologies reduces duplication of systems and data, improves reporting
13 capabilities, and strengthens long-term information management. This modernization has improved
14 collaboration, mobility, accessibility, and business continuity across Hydro's geographically dispersed
15 operations.

16 Hydro's modernization of aging IT infrastructure results in avoided costs by reducing ongoing
17 maintenance, support, and upgrade requirements associated with legacy systems. Updated platforms
18 improve operational efficiency, reduce reliance on specialized workarounds, and mitigate the cost of
19 sustaining obsolete technologies. In addition, modernization reduces exposure to cybersecurity and
20 system failure risks inherent in legacy infrastructure, thereby avoiding potential costs associated with
21 security incidents, emergency remediation, and service disruptions.

22 In addition, as discussed in Section 2.2.3, Hydro continues to strengthen its cybersecurity program through
23 ongoing investments in security technologies, governance, employee education, and awareness initiatives
24 to support the protection of corporate and operational technology environments.

⁸⁹ Approved in Board Order No. P.U. 1(2026).

⁹⁰ Geographic Information System is a tool utilized by multiple lines of business, which allows users to display and enhance geographic data, including mapping activities and environmental analysis. The software is primarily used for specific field operations and communications.

Digitizing and Automating Processes

The use of automated and electronic processes in place of manual or paper-based practices improves operational efficiency and reduces ongoing administrative effort.

In 2026, Hydro introduced a structured document management system. Implementation was completed in the first quarter of 2026 and is currently being piloted in the Major Projects division, with broader rollout to other functions intended in future years. The Omega 365 solution provides a centralized repository designed to improve visibility and consistency of project documentation by enabling teams to access current, approved versions of technical documents in a controlled environment. Built-in version control, audit history, and document workflows support traceability, governance, and structured review and approval processes, reducing reliance on manual and email-based practices.

The Microsoft 365 platform, implemented in 2025, provides employees with enhanced collaboration capabilities, secure remote access to information, and accessibility features that improve usability and inclusiveness for employees across the organization. The platform also includes Microsoft Copilot, which has been introduced across the organization with supporting governance and acceptable-use policies to ensure professional judgment, information protection, and responsible use of artificial intelligence tools. This supports workforce productivity through efficiencies such as meeting summarization, document drafting, information retrieval, and administrative automation.

Hydro is also implementing Accounts Payable automation software in 2026, which includes the implementation of a modern accounts payable system that is necessary to mitigate risks associated with security and controls, maintain favourable credit and business relationships, and avoid losses from incorrect payments and interest charges. The system will support timely and accurate payments, ensuring strong supplier relationships and promoting greater competition in tendering processes. It will also streamline accounts payable operations, reducing manual processing and avoiding future costs associated with errors, duplicate and incorrect payments, as well as potential interest and penalty charges.

These improvements, over time, allow for more efficient use of resources required to complete routine activities, reduce the risk of errors or rework and support effective cost management, limiting costs ultimately borne by customers.

2.4.6 Productivity Allowance

In previous GRAs in 2002, 2013, and 2017, the Board has ordered a productivity allowance or made disallowances pertaining to Hydro’s operating costs.^{91,92} In Board Order No. P.U. 49(2016) in relation to the 2013 GRA, the Board stated that the intention of a productivity allowance is “to provide an incentive to manage costs and find efficiencies.”⁹³ Hydro’s prior productivity allowances from the Board have ranged from \$2.0 to \$4.0 million in Hydro’s rate-setting years,⁹⁴ and most recently, the Board directed Newfoundland Power to include a \$2.0 million productivity allowance, equivalent to 2.5% of operating costs, within its 2025–2026 GRA.⁹⁵

In Board Order No. P.U. 3(2025), the Board said that it is required to balance the interests of the utility in the recovery of prudent costs with the interests of customers who are to receive reliable service at the lowest possible cost, in an environmentally responsible manner. The Board also noted that there is “currently significant upward pressure on customer rates.”

In Board Order No. P.U. 7(2002–2003), the Board stated that the onus is on Hydro to bring forward performance measures which clearly demonstrate the efficiency of its operations.⁹⁶ In the evidence of this application, Hydro has articulated how it is transforming its business and achieving operating cost savings and/or operational efficiencies. Absent these operational efficiencies, forecast operating expenditures would be materially higher over the test period.

As a further measure of recognizing customers’ concerns with the rising cost of electricity, and in light of past precedent, Hydro is including further cost savings in the form of a \$4.0 million productivity allowance to mitigate the increasing operating costs within the 2027 Test Year. This represents approximately 2.5% of operating costs, in line with the recent productivity allowance to Newfoundland Power, as directed by the Board.

⁹¹ In Board Order No. P.U. 7(2002–2003), the Board ordered that a productivity allowance of \$2.0 million should be applied to Hydro’s other operating costs.

⁹² In Board Order No. P.U. 49(2016), the Board made significant disallowances with respect to the proposed 2015 Test Year revenue requirement related to a number of specific costs, including salaries and benefits, professional services and travel expenses.

⁹³ Board Order No. P.U. 49(2016), p. 53/27–28.

⁹⁴ In Board Order No. P.U.16(2019), the Board reduced Hydro’s test year operating costs by \$4 million in 2018 and 2019.

⁹⁵ Board Order No. P.U. 3(2025), p. 22/2–3.

⁹⁶ Board Order No. P.U. 7(2002–2003), p. 73.

1 Identifying and implementing sustainable cost savings that result in lower operating costs is an ongoing
2 effort and must be undertaken prudently to mitigate against unintended negative consequences on safety
3 or reliability.

4 In Board Order No. P.U. 49(2016) arising from Hydro's 2013 GRA, the Board recognized that Hydro had a
5 limited opportunity to identify efficiencies within the test year due to the timing of receipt of the GRA
6 Order.

7 By adopting a productivity allowance, Hydro is demonstrating its continued commitment to prudent cost
8 management and will seek further opportunities to identify and implement additional efficiency
9 opportunities beyond those identified to date. Cost reduction measures need to be sustainable and must
10 not negatively impact safety, system reliability, or customer service.

11 Applied from an enterprise-wide perspective, the productivity allowance has been allocated across
12 departments as a percentage of total budgeted dollars to reinforce organizational accountability and the
13 prioritization of cost discipline at all levels. Operational efficiency efforts are reflected in the 2027 Test
14 Year forecast through the avoidance of costs that would otherwise be required to maintain reliability and
15 service levels. These efficiencies are embedded in the forecast as avoided expenditures rather than
16 discrete line-item reductions. Actions to contain costs must be managed diligently to avoid unintended
17 consequences such as reduced safety performance or reliability performance.

18 ***Productivity Outlook***

19 Looking forward, Hydro will continue to advance and evolve the continuous improvement of its business,
20 as described in Section 2.4, with a focus on strengthening operational performance while maintaining
21 disciplined cost control. Workforce management practices will increasingly emphasize proactive planning,
22 effective utilization of internal expertise, and targeted skills development to ensure the organization has
23 the capacity and capabilities required to meet its evolving mandate. At the same time, Hydro will further
24 refine its contracting and procurement practices to reduce risk, particularly around cost and schedule
25 uncertainty, mitigate supply chain risks, and secure critical resources efficiently in a highly competitive
26 market.

27 Hydro's continued investment in technology in areas such as remote access, collaboration tools, data
28 analytics, and field-enabled technologies is expected to drive operational improvements by increasing

1 system visibility, responsiveness, and coordination across geographically dispersed assets. The ability to
2 remotely monitor, diagnose, and in certain cases operate equipment reduces response times and supports
3 earlier intervention before issues escalate into outages or equipment failures. In parallel, enhanced data
4 analytics and asset condition reporting improve the quality and timeliness of decision-making, enabling
5 more targeted maintenance and optimized resource deployment. Field technologies and digitized
6 processes further increase productive field time by reducing administrative burden and improving real-
7 time access to information. Collectively, these capabilities support improved reliability outcomes, more
8 efficient workforce utilization, and stronger business continuity during system events, contributing to a
9 more resilient and responsive utility operation.

10 These technological improvements translate into both direct cost reductions and avoided costs over time,
11 with benefits becoming more pronounced as adoption matures and data quality improves. By increasing
12 its use of Operating Technology, Hydro enhances its ability to execute proactive and cost-effective
13 interventions. Reduced travel, fuel consumption, and contractor reliance provide direct savings for
14 customers. Earlier detection of asset issues and enhanced predictive capabilities mitigate the risk of high-
15 cost emergency repairs, unplanned outages, and premature asset replacement. Modernized IT systems
16 enhance operations by improving compatibility across systems, streamlining upgrade requirements,
17 mitigating cybersecurity risks and avoiding costs associated with manual administration and legacy
18 systems. This cumulative effect strengthens Hydro's ability to manage long-term cost pressures while
19 maintaining system reliability, resulting in sustained value for customers.

20 To address certain high-risk commodities and services whose procurement challenges pose a risk to
21 Hydro, Hydro has established a Strategic Procurement Committee to address growing supply chain
22 challenges driven by widespread electrification across Canada and other jurisdictions. These challenges
23 include limited original equipment manufacturer capacity, reduced bid competition, demand-induced
24 scarcity and price pressures, extended equipment lead times, and broader inflationary impacts such as
25 foreign exchange movements and tariffs. The Committee is mandated to review practices across the utility
26 sector and other industries to identify effective risk mitigation strategies and implement measures to
27 derisk these procurements. Strategic procurement initiatives are intended to support Hydro's ability to
28 secure qualified professionals, meet its legislated obligation to ensure adequate supply, and manage cost
29 and schedule risks in a manner that minimizes impacts on customers.

1 These improvements are complemented by Hydro's broader efforts to modernize its information and
2 operational technology to improve operational outcomes and offset operating costs for customers.
3 Collectively, alongside economic system dispatch, maximization of hydrologic resources, and the use of
4 enabling technologies, these initiatives position Hydro to meet productivity allowance targets, adapt to
5 increasing system complexity, maintain reliability, and manage future investment responsibly. The
6 resulting operational efficiencies and cost avoidance will increase Hydro's contributions to rate mitigation
7 and help limit growth in operating costs for the benefit of customers.

8 **2.5 Summary**

9 Hydro manages its business in a manner that is consistent with its legislated mandate as a Crown
10 corporation and regulated public utility, with accountability to customers and the people of
11 Newfoundland and Labrador at the forefront. Through transparent decision-making, regular engagement
12 with customers and stakeholders, and adherence to the regulatory framework, Hydro is navigating a
13 period of significant change in the electricity sector while maintaining a clear focus on reliability,
14 customers and least-cost service.

15 Hydro's sustained customer satisfaction results and stable reliability performance reflect a balanced
16 approach to serving customers across diverse and geographically dispersed systems. Consistent residential
17 and general service satisfaction scores, increasing use of digital service tools, and positive feedback on
18 system reliability indicate that Hydro's operational practices are effective and aligned with customer
19 expectations. At the same time, Hydro has demonstrated prudence in managing its aging infrastructure
20 and integrating new assets, including the Muskrat Falls Assets, while ensuring that reliability
21 improvements and system investments are pursued in a prudent manner.

22 Good utility and business practices are evident in Hydro's system operations. The optimization of
23 hydrologic resources, strategic use of imports and exports, and growing integration of renewable energy
24 in Isolated systems have delivered tangible benefits to customers through cost savings, generation of
25 funding for rate mitigation, and environmental performance. Hydro's load forecasting processes and
26 workforce planning also support informed, forward-looking decision-making, ensuring that the
27 organization has the capability and expertise required to meet future system needs while managing risk in
28 a highly competitive labour market.

1 Despite significant inflationary pressures since the 2019 Test Year, Hydro has achieved meaningful
2 reductions in both labour and non-labour operating costs through organizational efficiencies and
3 productivity improvements. These efforts have allowed Hydro to absorb cost pressures that are largely
4 beyond its control, limiting impacts on customer rates. The inclusion of a productivity allowance in the
5 2027 Test Year further demonstrates Hydro's commitment to continuous improvement and
6 responsiveness to Board precedent and customer concerns regarding affordability.

7 Hydro's proposed 2027 Test Year costs are reasonable and necessary to support safe, reliable, and
8 least-cost service, while enabling the measured growth of the system to meet future demand. Through
9 disciplined cost management, operational practices, and ongoing engagement with customers and
10 stakeholders, Hydro manages its business in the best interests of customers and in fulfillment of its
11 statutory obligations to the province.

Chapter 3

Regulated Operating Costs



Chapter 3: Regulated Operating Costs

3.1 Operating Costs

The 2027 Test Year operating costs are forecast to be approximately 10% lower¹ than the 2019 Test Year forecast in real dollars, as discussed in Chapter 2.² The majority of these savings reflect targeted actions grounded in cost management, operational practices, and long-term value for customers. Hydro's performance is reflective of prudent cost management. Hydro's operating costs represent approximately 20% of the 2027 Test Year revenue requirement, consistent with the 2019 Test Year. If rate mitigation is not included, Hydro's operating costs represent 12% of the costs to serve customers.³

Schedules B-I, B-II and B-III detail operating costs from the 2019 Test Year through the 2027 Test Year. In this chapter, given the passage of time and elevated inflation since Hydro's last GRA,⁴ Hydro has utilized its 2024 results as the most recent comparator to the 2027 Test Year.⁵ The selection of 2024 as a comparator was most appropriate, as Hydro's final 2025 results were not available during the preparation of the filing.

3.1.1 2027 Test Year

Hydro has compiled its forecast for the 2027 Test Year using a combination of zero-based budgeting⁶ and a historical average approach.⁷ The major cost components within Hydro's operating forecast were derived using zero-based budgeting, including, but not limited to, employee salaries and benefits, professional services and SEM costs. These costs make up over 80% of Hydro's operating costs in the 2027 Test Year. Where operating costs are expected to be consistent in normal year-to-year operations,

¹ 2019 Test Year in Real Dollars (\$173.3) - 2027 Test Year in Nominal Dollars (\$156.4) / 2019 Test Year in Real Dollars (\$173.3) = 9.8%.

² Please refer to Chapter 2, Section 2.3.1 and Section 2.3.2. Differences between the 2019 Test Year and 2027 Test Year operating expenses include, but are not limited to, amortizations and deferred expenses to the General Expenses Capitalized Deferral Account as approved in Board Order No. P.U. 32(2025).

³ 2027 Test Year (\$156.4) / Total costs to serve customers is equal to revenue requirement with rate mitigation added back (\$797.7 + \$502.0) \$1,299.7 = 12.0%.

⁴ Compounded inflation rate for the GDP deflator from 2019 to 2024 is 23%.

⁵ Hydro's most recent audited fiscal year-end actuals from 2024 are currently under review by the Board's auditor, Grant Thornton and a final report is anticipated in the second quarter of 2026.

⁶ Zero-based budgeting is a strategic financial approach where all expenses must be justified for each new period, starting from a zero base, rather than adjusting previous budgets.

⁷ For cost categories where a historical average approach was applied, Hydro used a three-year average of historical actual and forecast expenditures from 2022 to 2024 to calculate the 2025 budget. Costs were then escalated from 2025 to derive the 2026 Forecast and the 2027 Test Year. Non-labour costs were escalated using the forecasted GDP deflator, and labour costs were escalated using internal labour assumptions.

these cost categories were derived using a historical average, reflecting Hydro’s recent experience and expected pattern for the coming period. This approach has resulted in some variances between the 2019 Test Year and the 2027 Test Year forecasts for these categories of expenditures; however, the 2027 Test Year forecast is more reflective of the level of operating expenditures required to operate Hydro’s business to maintain the delivery of reliable electricity service to customers.

Hydro’s 2027 Test Year operating forecast of \$156.4 million reflects a \$4.0 million, or 2.5%, productivity allowance embedded within the overall forecast to incorporate savings across Hydro’s operating costs, as discussed in Chapter 2, Section 2.4.6. Chart 3-1 shows Hydro’s 2024 operating costs escalated to 2027,⁸ as well as actual and forecast operating costs for each year.

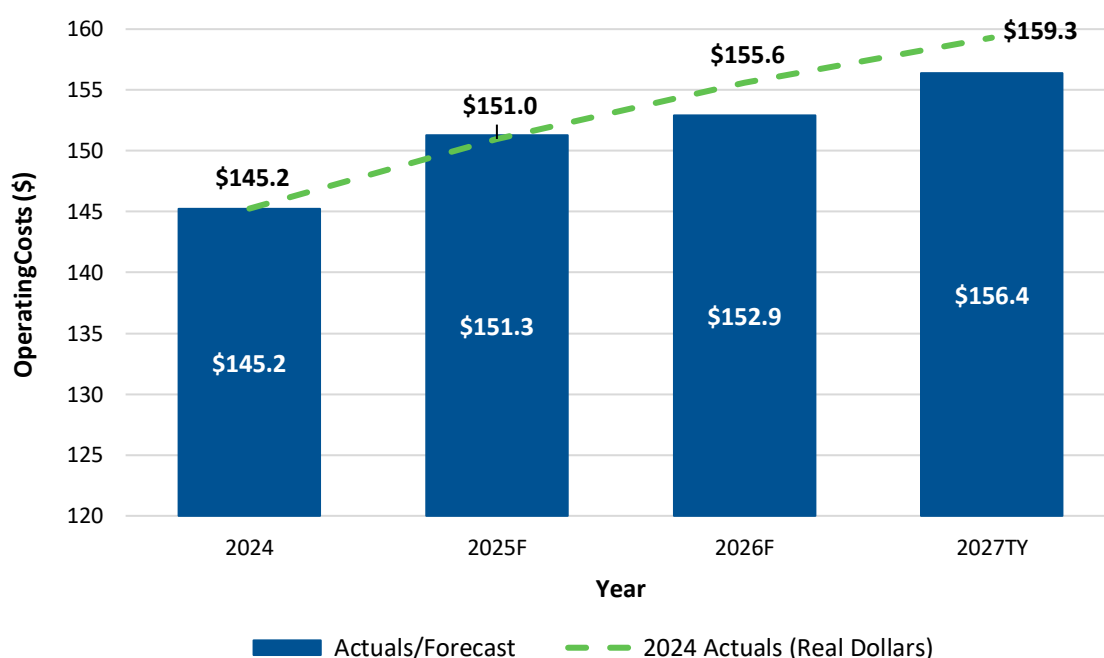


Chart 3-1: Hydro’s Operating Expenses 2024 to 2027 Test Year (\$ Millions)

From 2024 to 2027, inflation is expected to result in an increase of more than 10%, or approximately \$14.1 million in operating costs.⁹ Like many other utilities, Hydro is experiencing substantial cost pressures as a result of increased demand for materials and services within the electricity industry and

⁸ Hydro escalated 2024 non-labour costs using the GDP deflator; 2024 labour costs have been inflated using historical Statistics Canada data and internal labour assumptions.

⁹ 2024 Operating Expenses in Real Dollars (\$159.3) - 2024 Operating Expenses in Nominal Dollars (\$145.2) = \$14.1.

major assets requiring increased levels of maintenance expenditures to maintain reliability due to age. At the same time, there is increased competition for labour and resources. However, during a period of growth in Hydro's business, cost management has limited the overall operating cost increase to a level below inflation.

As discussed in Chapter 2, drivers of labour cost increases between 2024 and the 2027 Test Year were primarily related to salaries and benefits. Hydro must be able to attract and retain the skills required to manage the utility according to *Good Utility Practice* in the near and long-term, and therefore must compensate its employees prudently. The impact of labour cost increases were partially offset by expenses deferred to the General Expenses Capitalized Deferral Account.¹⁰

Drivers of non-labour cost changes between 2024 and the 2027 Test Year were primarily related to professional services, materials, contract labour and other maintenance-related expenses, which were subject to cost escalations due to market conditions. These increases are partially mitigated by the \$4.0 million productivity allowance commitment.

While Hydro has successfully mitigated inflationary pressures through sustained cost management efforts, productivity improvements, and operational efficiencies, it is not feasible to continuously absorb these pressures and grow at the same time without impacting Hydro's ability to safely and reliably deliver service. Hydro is responsible for ensuring it can continue to meet customers' needs and fulfill its mandate to provide the least-cost, reliable electricity service in an environmentally responsible manner and therefore must act accordingly. This requires prudent expenditures, recognizing that continued deferral or absorption of unavoidable cost increases is not prudent nor sustainable over the long term.

3.1.2 Operating Costs by Type

Hydro classifies its operating costs by cost type and by function. For example, the salary costs of a Power Line Technician in Transmission and Rural Operations would be classified in two ways: (i) by cost type, as

¹⁰ Hydro's General Expenses Capitalized Deferral Account records and defers capital-related overhead and general expenses to be recovered over a period consistent with the composite depreciation rate in the latest depreciation study approved by the Board. Throughout this chapter, Hydro's operating costs in 2025F, 2026F and 2027TY are shown net of deferrals to the General Expenses Capitalized Deferral Account as approved in Board Order No. P.U. 32(2025).

a labour cost; and (ii) by function, as a Transmission and Rural Operations cost in Operations. Schedules B-I and B-II detail operating costs by cost type and cost function, respectively.

Hydro's operating costs are presented in the following cost types as follows:

- Labour;
- SEM;
- Other; and
- Cost Allocations (Recoveries).¹¹

Table 3-1 provides a breakdown of Hydro's operating costs by cost type in the 2019 Test Year and for the period 2024 to the 2027 Test Year.

Table 3-1: Hydro's Operating Costs by Cost Type (\$ Millions)¹²

Cost Type	2019 Test Year	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Labour	85.5	88.5	88.2	93.4	96.4
SEM	26.8	24.6	28.6	29.8	27.5
Other	29.6	32.3	35.2	33.8	35.3
Cost Allocations (Recoveries)	(5.0)	(0.1)	(0.8)	(4.1)	(2.9)
Total Operating Costs	136.9	145.2	151.3	152.9	156.4

Labour Costs

Labour costs in the 2027 Test Year of \$96.4 million are approximately 9% lower than the 2019 Test Year in real dollars.¹³ Labour costs include salaries, benefits, and overtime, among other salary-related costs associated with Hydro's regulated operations. Drivers of the \$10.9 million variance in labour costs in the eight-year period between the 2019 Test Year and the 2027 Test Year include higher salary costs related to market-based adjustments, increased FTEs,¹⁴ as well as overtime costs;¹⁵ offset by variations in other

¹¹ Includes both costs charged to and recovered from other non-regulated lines of business through administration fees, deferral of costs related to Hydro's CDM program and productivity allowances.

¹² Numbers may not add due to rounding.

¹³ 2019 Test Year Labour Costs in Real Dollars (\$105.7) - 2027 Test Year Labour Costs in Nominal Dollars (\$96.4) / 2019 Test Year in Real Dollars (\$105.7) = 8.8%. Please refer to Chart 2-11.

¹⁴ For further discussion on Hydro's FTEs, please refer to Chapter 2, Section 2.2.4.

¹⁵ Overtime costs reflect the three-year average of overtime labour from 2022 to 2024, adjusted for labour inflation.

- 1 labour-related costs, including Board-approved changes as a result of Hydro’s recent General Expenses
2 Capitalized Application.
- 3 Table 3-2 provides a breakdown of Hydro’s labour costs by cost type in the 2019 Test Year and for the
4 period of 2024 to the 2027 Test Year.

Table 3-2: Hydro’s Labour Costs by Cost Type (\$ Millions)¹⁶

Cost Type	2019 Test Year	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Salaries	77.4	82.0	89.3	92.0	96.2
General Expenses Capitalized	-	-	(6.1)	(6.4)	(6.6)
Overtime	4.9	7.2	6.8	7.2	7.4
Other Labour-Related Costs ¹⁷	3.2	(0.7)	(1.9)	0.6	(0.6)
Total Labour Costs	85.5	88.5	88.2	93.4	96.4

- 5 Labour costs have increased by approximately \$7.9 million from 2024 through the 2027 Test Year,
6 primarily as a result of salary adjustments¹⁸ required to begin closing the gap with its utility comparators,
7 as outlined in the Southlea report, for both non-union and union personnel.¹⁹ Salary increases associated
8 with union personnel are a reflection of that negotiated through Hydro’s collective agreements. Increases
9 in labour costs related to additional FTEs between 2024 and the 2027 Test Year are largely offset by
10 deferrals to Hydro’s General Expenses Capitalized Deferral Account, as a portion of salaries associated
11 with these new FTEs are capitalized and are not reflected in Hydro’s operating costs.²⁰
- 12 Overtime from 2024 to the 2027 Test Year reflects increasing labour rates and a change in Hydro’s
13 methodology for budgeting overtime, using the historic average approach noted in Section 3.1.1.
14 Overtime within Hydro’s 2019 Test Year forecast was lower than 2019 actuals, representing 5.7% of
15 labour costs, and not representative of that which is required to safely and reliably operate Hydro’s
16 assets. For the 2027 Test Year, Hydro’s overtime forecast is based on a historical average, escalated for
17 labour inflation, better reflecting overtime required for its operations. Overtime is a necessary and

¹⁶ Numbers may not add due to rounding.

¹⁷ Other labour-related costs consist of employee benefits and allowances, labour recharge, and other salary-related costs.

¹⁸ Hydro provided economic increases of 4% in both 2024 and 2025. Hydro has forecasted modest salary adjustments through its 2027 Test Year that are required to continue to close the gap with Atlantic Canadian utility comparators.

¹⁹ Please refer to Chapter 2, Section 2.2.4.

²⁰ 100% of Major Projects’ salary costs are capitalized as approved in Board Order No. P.U. 32(2025).

prudent expense for Hydro, given the nature of its 24-7 work in providing an essential service and comprises approximately 7.7% of its total labour costs.²¹ Hydro's overtime is driven by planned operating activities, responses to unplanned customer outages, and periods of extra effort required by staff to support critical business deliverables. As described in Chapter 2, overtime, both costs and hours worked, is closely monitored and reviewed by the business through regular reporting mechanisms such as electronic dashboards, which provide a comprehensive view of operational requirements, areas requiring additional effort, and performance against budgets. Overall, Hydro's overtime is a prudent and necessary component of its operations and is subject to active management and oversight to ensure that it is minimized where possible and incurred on a least-cost basis consistent with safe and reliable service.

These increases in labour costs are partially offset by the implementation of the General Expenses Capitalized Deferral Account, which reduced operating labour costs by \$6.6 million in the 2027 Test Year.

SEM Costs

SEM costs are comprised of materials, contract labour and other costs associated with maintenance activities necessary to operate Hydro's assets in accordance with *Good Utility Practice*. SEM costs in the 2027 Test Year have increased by \$2.9 million from 2024 due to higher contract labour and material costs, primarily driven by market-driven cost escalations.²²

Other

Other costs include, but are not limited to, professional services (including software costs), transportation, travel, training, miscellaneous costs (including taxes) and equipment rentals. A list of included costs is provided in Schedule B-I. Costs in this category are forecast to increase by \$3.0 million in the 2027 Test Year compared to 2024, driven primarily by higher professional services, miscellaneous, and transportation expenses, partially offset by reductions in equipment rental costs.

Professional services costs increased between 2024 and the 2027 Test Year by \$2.2 million due to:
(i) higher software costs driven by new requirements (i.e., such as cybersecurity and cloud-related

²¹ 2027 Test Year Overtime Costs (\$7.4) / 2027 Test Year Labour Costs (\$96.4) = 7.67%.

²² Compounded inflation rate of 7.3% from 2024 to 2027 Test Year based on GDP deflator.

subscription fees, and inflationary increases); and (ii) amortization of previously deferred studies²³ and forecast GRA hearing costs. Drivers of the increase in miscellaneous expenses of \$1.1 million include: (i) higher municipal and payroll taxes; (ii) increases in training costs associated with safety, legislative and job-related training; and (iii) CDM initiatives.²⁴ Transportation cost increases of \$0.6 million are related to aircraft costs for operations support as a result of increases in market rates. These increases were partially offset by a decrease of \$0.8 million in equipment rentals due to changing operational requirements.

Cost Allocations (Recoveries)

Cost allocations (recoveries) include costs charged to and recovered from other non-regulated lines of business through administration fees, deferral of costs related to Hydro's CDM program and productivity allowances, as shown in Table 3-3. External cost recoveries represent costs that have been presented elsewhere within Hydro's operating costs. Further detail on cost allocations (recoveries) is included in Schedule B-III.

Table 3-3: Cost Allocations (Recoveries) (\$ Millions)²⁵

Cost Type	2019 Test Year	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Net Administration Fees ²⁶	2.8	5.2	6.5	6.1	4.7
Productivity Allowance	(5.1)	-	-	(4.0)	(4.0)
CDM Program Deferral	(2.1)	(1.4)	(1.8)	(1.9)	(1.9)
External Cost Recoveries	(0.5)	(2.0)	(2.3)	(0.3)	(0.3)
Removal and Decommissioning Recovery ²⁷	-	(1.7)	(2.8)	(3.5)	(1.0)
Other Cost Recoveries	(0.1)	(0.3)	(0.4)	(0.5)	(0.5)
Total Cost Allocations (Recoveries)	(5.0)	(0.1)	(0.8)	(4.1)	(2.9)

In the 2027 Test Year, cost allocations (recoveries) is a credit balance which increased by \$2.8 million in comparison to 2024, primarily due to the inclusion of Hydro's productivity allowance of \$4.0 million,

²³ Previously deferred studies included those associated with Phase Two of the Board's investigation into the January 2014 outages, Holyrood TGS Life Extension Condition Assessment, and the *Reliability and Resource Adequacy Study Review*.

²⁴ Costs associated with CDM initiatives have been deferred for future recovery, as shown in Table 3-3.

²⁵ Numbers may not add due to rounding.

²⁶ Non-regulated administration fees net of Hydro's regulated administration fee recovery.

²⁷ In Board Order No. P.U. 30(2019), the Board approved Hydro's proposed depreciation methodology, which includes the provision for removal costs.

1 partially offset by a decrease in external cost recoveries of \$1.7 million due to changes in requirements
2 from and contracts with external parties.

3 ***Intercompany Guidelines***

4 Cost allocations related to shared services departments through the use of administration fees are
5 governed by Hydro's Intercompany Guidelines, which were updated in 2026. Variances in administration
6 fees are a result of: (i) cost escalation over the period; (ii) changes to the structure of shared services
7 departments (i.e., combining previously dedicated teams, such as Accounts Payable); and (iii) the
8 addition of new administration fees. These changes were reviewed by an independent expert and are
9 discussed within Exhibit 2.²⁸

10 The Hydro organizational structure includes both regulated and non-regulated lines of business,
11 providing services to one another in relation to activities associated with the development, generation,
12 transmission, marketing and distribution of electricity.²⁹ Hydro's Intercompany Guidelines outline the
13 methodologies and charges between lines of business that apply to intercompany transactions.

14 The guidelines are based on the principle of cost-based recovery. There is no profit component, and time
15 worked for other lines of business is tracked and charged accordingly. Costs associated with the operation
16 of certain departments that provide common services available to all lines of business are allocated
17 through administration fees, as outlined in Hydro's Intercompany Guidelines. In the 2027 Test Year, the
18 delivery of common services includes: Human Resources; Information Systems; Operating Technology;
19 Safety, Health and Environment; Procurement; Building and Office Services; Accounts Payable; General
20 Ledger; Corporate Secretary; Executive; and Culture and Employee Engagement. The departments that
21 provide the common services are based in both regulated and non-regulated lines of business.

22 Hydro issued an update to its Intercompany Guidelines in 2026. The updated guidelines were reviewed
23 by its expert, KPMG, which evaluated the allocation methodology based on regulatory precedents from
24 the Board, the Alberta Utilities Commission, the Ontario Energy Board and other jurisdictions across

²⁸ "Intercompany Transactions Costing Guidelines Review – Newfoundland and Labrador Hydro," KPMG LLP, March 26, 2026. Provided in "Review of Newfoundland and Labrador Hydro's Intercompany Transactions Costing Guidelines," Newfoundland and Labrador Hydro, March 30, 2026, att. 2.

²⁹ The non-regulated lines of business include activities exempt from regulation through Government direction or the operation of the Act or excluded from recovery from customers through Board Orders.

Canada. In its review, KPMG found that the methodology used by Hydro was a reasonable mechanism to allocate shared costs between regulated and non-regulated lines of business, and that allocators are based on clear and quantifiable measures. The updates to Hydro’s Intercompany Guidelines as a result of the review were not substantial. The updates include four new administration fees for allocation of costs from small departments providing common services to the business, and the introduction of a Hybrid Allocator to allocate certain costs,³⁰ similar to that used by comparable utilities across other Canadian jurisdictions. KPMG concluded that:

While Hydro has gone through organization changes and made modifications to its intercompany transactions (largely in the form of combining teams into shared services and creating new Admin Fees), the fundamental approach of Hydro’s *Intercompany Transaction Costing Guidelines (2026)* remains largely consistent from the 2013 and 2017 iterations which were filed with the Board under respective GRAs.³¹

The Intercompany Guidelines continue to be reasonable, ensuring that regulated customers pay for only those costs directly related to the provision of electricity service.

3.1.3 Operating Costs by Function

As demonstrated in Table 3-4, Hydro’s operating costs are segregated by cost function as follows:

- Operations; and
- General and Administration.

Table 3-4: Hydro’s Operating Costs by Cost Function (\$ Millions)³²

Cost Function	2019 Test Year	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Operations	108.1	110.4	115.6	119.5	121.3
General and Administration	34.2	34.9	35.7	33.4	35.0
Less Allowances ³³	(5.3)	-	-	-	-
Total	136.9	145.2	151.3	152.9	156.4

³⁰ Hydro’s Hybrid Allocator uses the line of business total gross capital assets and total operating costs, both weighted at 50%, to calculate the allocation of costs.

³¹ “Intercompany Transactions Costing Guidelines Review – Newfoundland and Labrador Hydro,” KPMG LLP, March 26, 2026, p. 39, Table 37.

³² Numbers may not add due to rounding.

³³ In Board Order No. P.U. 16(2019), the Board included a \$4.0 million productivity allowance, and increased vacancy allowance by 15 FTEs (\$1.3 million) as per the 2017 GRA Settlement Agreement, which were not allocated by function and department. In the 2027 Test Year, Hydro included a consistent vacancy allowance of 55 FTEs and a \$4.0 million productivity allowance, which was allocated by function and department.

Operations Costs

Operations costs, shown in Table 3-5, are further segmented by functional area, which includes:

- Transmission and Distribution;
- Production;
- Engineering Services;
- System Planning and NLSO;
- Major Projects and Asset Management; and
- Operating Technology.

Table 3-5: Hydro's Operating Costs – Operations by Functional Area (\$ Millions)³⁴

Functional Area	2019	2024	2025	2026	2027
	Test Year Restated ³⁵	Actual	Forecast	Forecast	Test Year
Transmission and Distribution	41.7	39.3	41.8	44.0	45.1
Production	43.7	40.9	42.1	43.5	44.6
Engineering Services	6.0	5.6	5.0	5.1	5.1
System Planning and NLSO	4.8	8.7	10.7	9.8	10.0
Major Projects and Asset Management ³⁶	0.6	2.3	2.0	2.4	2.5
Operating Technology	11.2	13.5	14.0	14.8	14.1
Total Operations Costs	108.1	110.4	115.6	119.5	121.3

Hydro's operations costs are increasing by approximately 12%³⁷ from 2019 to 2027 Test Year, below inflationary levels of approximately 28% during that period.³⁸

³⁴ Numbers may not add due to rounding.

³⁵ Hydro has presented the 2019 Test Year costs in alignment with its current organizational structure.

³⁶ The Major Projects division did not exist in 2019; therefore, costs within the 2019 Test Year are contributed to Hydro's Asset Management department.

³⁷ 2027 Test Year Total Operations Costs (\$121.3) - 2019 Test Year Restated Total Operations Costs (\$108.1) / 2019 Test Year Restated Total Operations Costs (\$108.1) = 12.2%.

³⁸ Weighted inflation rate compounded year over year from 2019 Test Year to 2027 Test Year using GDP deflator (32%) and labour inflation (25%).

Operations costs are increasing by 10%³⁹ over the four-year period from 2024 to the 2027 Test Year. This increase is primarily driven by increases in salary and benefits costs over the period, as discussed in Chapter 2, which are partially offset by the impacts of Hydro's approved General Expenses Capitalized Application. 2027 Test Year costs for Transmission and Distribution and Production departments increased by \$5.8 million and \$3.7 million, respectively, when compared to 2024. In addition to increases in labour costs for these departments, another key driver of the increase includes market-driven contract cost escalations, including higher contract labour costs. System Planning and NLSO costs increased by \$1.3 million from 2024 to 2027 Test Year due to increased labour costs and higher consultant costs related to studies supporting the *Reliability and Resource Adequacy Study Review*.

General and Administration

General and administration costs, shown in Table 3-6, are further segmented by functional area, which includes:

- Executive;
- Financial Services and Other;
- People, Culture and Corporate Affairs; and
- Regulatory Affairs, Customer Service and Energy Optimization.

Table 3-6: Hydro's Operating Costs – General and Administration by Functional Area (\$ Millions)⁴⁰

Functional Area	2019	2024	2025	2026	2027
	Test Year Restated ⁴¹	Actual	Forecast	Forecast	Test Year
Executive	2.9	2.7	3.3	2.6	2.7
Financial Services and Other ⁴²	10.1	12.3	11.2	9.5	9.2
People, Culture and Corporate Affairs	10.1	9.7	10.8	10.9	11.5
Regulatory Affairs, Customer Service and Energy Optimization	11.2	10.2	10.3	10.4	11.7
Total General and Administration Costs	34.2	34.9	35.7	33.4	35.0

³⁹ 2027 Test Year Total Operations Costs (\$121.3) - 2024 Actual Total Operations Costs (\$110.4) / 2024 Actual Total Operations Costs (\$110.4) = 9.9%.

⁴⁰ Numbers may not add due to rounding.

⁴¹ Hydro has presented 2019 Test Year costs reclassified to align with its current organizational structure.

⁴² Other includes Supply Chain, Building Services, Commercial, and Information Systems administration fees.

Hydro's general and administration costs are increasing by approximately 2%⁴³ from 2019 to 2027 Test Year, below inflationary levels of approximately 28% during that period.

The general and administration costs are consistent, increasing by less than 1%⁴⁴ or \$0.1 million from 2024 to 2027 Test Year. Cost increases in People, Culture and Corporate Affairs, and Regulatory Affairs and Customer Service are primarily driven by salary and benefits costs, in addition to amortizations of regulatory deferrals⁴⁵ and higher Board-related costs associated with regulatory applications and proceedings. These increases are largely offset by higher administration fee recoveries and the impacts of Hydro's approved Generalized Expenses Capitalized Deferral Account.

3.2 Summary

Hydro's costs have an impact on customer rates; therefore, Hydro focuses on cost management as a means through which to mitigate rate impacts on its customers. In the 2027 Test Year, Hydro's total regulated operating costs are \$156.4 million, which includes a \$4.0 million productivity allowance commitment.

Drivers of labour cost increases between 2024 and the 2027 Test Year are primarily related to salaries and benefits. Hydro must be able to attract and retain the skills required to manage the utility according to *Good Utility Practice* in the near and long-term, and therefore must compensate its employees prudently. Drivers of non-labour cost changes between 2024 and the 2027 Test Year are primarily related to professional services, materials, contract labour and other maintenance-related expenses, which were subject to cost escalations due to market conditions.

Increases in operating costs through the 2027 Test Year have remained below inflation. While Hydro has successfully mitigated inflationary pressures, it is not feasible to continuously absorb these pressures and grow at the same time without impacting Hydro's ability to safely and reliably deliver service. Hydro is committed to effective cost management across both its regulated and non-regulated operations,

⁴³ 2027 Test Year Total General and Administration Costs (\$35.0) - 2019 Test Year General and Administration Costs (\$34.2) / 2019 Test Year General and Administration Costs (\$34.2) = 2.3%.

⁴⁴ 2027 Test Year Total General and Administration Costs (\$35.0) - 2024 Actual General and Administration Costs (\$34.9) / 2024 Actual General and Administration Costs (\$34.9) = 0.3%.

⁴⁵ Amortization of regulatory deferrals includes forecast GRA costs, studies associated with Phase Two of the Board's investigation into the January 2014 outages and Board costs for Hydro's *Reliability and Resource Adequacy Study Review* proceeding, all of which are included in the 2027 Test Year.

- 1 which supports Hydro's ability to internally fund its rate mitigation requirements in accordance with
- 2 Government's rate mitigation plan.

Chapter 4

Muskrat Falls Supply Costs



Chapter 4: Muskrat Falls Supply Costs

4.1 Overview

Hydro uses energy and capacity generated by the Muskrat Falls Assets to supply customers on the Island Interconnected System.

OC2013-343¹ and the Muskrat Falls Project Exemption Order² expressly provide that all associated costs are fully recoverable through Island Interconnected System customer rates and are not subject to disallowance, reduction, or regulatory adjustment.

Government's rate mitigation plan effectively mitigates approximately 39%³ of Hydro's overall costs. This provides rate predictability up to 2030 with regard to Hydro's electricity rate increases by offsetting a portion of Hydro's supply costs. Although these costs are outside the Board's jurisdiction for review or prudence assessment, Hydro is providing this information in the interest of transparency and accountability, to ensure stakeholders and customers have the opportunity to consider all material costs reflected in Hydro's costs of providing service.

Two main contracts provide for the recovery of the Muskrat Falls Project costs from Hydro and feed Hydro's supply cost associated with the Muskrat Falls Project: (i) the Muskrat Falls PPA⁴ between Hydro and Muskrat Falls Corporation recovers the costs of the Muskrat Falls Hydroelectric Generating Facility and Labrador Transmission Assets; and (ii) the Transmission Funding Agreement⁵ between Hydro, LIL Limited Partnership and LIL Operating Corporation recovers the costs of the LIL.

Variances in Muskrat Falls supply costs from those included in Hydro's most recently approved test year are currently deferred through the Supply Cost Variance Deferral Account,⁶ approved by the Board effective November 1, 2021.⁷ In its application for the Supply Cost Variance Deferral Account, Hydro

¹ Government of Newfoundland and Labrador, *Order in Council OC2013-343*, November 29, 2013.

² *Muskrat Falls Project Exemption Order*, NLR 120/13, <https://canlii.ca/t/524p3>.

³ Total costs to serve customers is equal to revenue requirement with rate mitigation added back (\$797.7 + \$502.0 = \$1,299.7). Rate Mitigation (\$502.0) / Total Cost to Serve Customers (\$1,299.7) = 39%. Please refer to Chapter 5 for additional information on Hydro's revenue requirement.

⁴ The initial Muskrat Falls PPA was executed between Muskrat Falls and Hydro on November 29, 2013, and was replaced with the Amended & Restated PPA on April 14, 2023.

⁵ The Transmission Funding Agreement was executed on November 29, 2013.

⁶ The 2019 Test Year did not have any Muskrat Falls supply costs included, and therefore, the full balance of Muskrat Falls PPA and Transmission Funding Agreement costs charged to Hydro to date is currently included in the deferral.

⁷ Board Order Nos. P.U. 33(2021) and P.U. 4(2022).

indicated it would provide additional evidence on a long-term approach to the Supply Cost Variance Deferral Account in its next GRA. Hydro's proposal for its Long-Term Supply Cost Variance Deferral Account is included in Chapter 5, Section 5.7. This account is proposed to capture supply cost variances from Hydro's test year, effective January 1, 2027, including those associated with the Muskrat Falls PPA and Transmission Funding Agreement.

Table 4-1 outlines the Muskrat Falls PPA and Transmission Funding Agreement supply costs for the period of 2024⁸ to the 2027 Test Year.

Table 4-1: Total Muskrat Falls Supply Costs (\$ Millions)

	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Muskrat Falls PPA	273.3	323.0	323.6	323.9
Transmission Funding Agreement	448.1	461.3	466.8	465.1
Subtotal Per Agreements	721.4	784.3	790.4	789.0
Muskrat Falls PPA Sustaining Capital Deferral ⁹	(10.8)	(8.4)	(18.9)	(8.6)
Total Muskrat Falls Supply Costs	710.6¹⁰	775.9	771.5	780.4

4.2 Hydro's Energy Under the Muskrat Falls PPA

Schedule 2 to the Muskrat Falls PPA provides the Initial Load Forecast, which represents the forecast of customer load requirements on the Island Interconnected System at the time the original PPA was executed in November 2013 (i.e., NL Native Load).¹¹ This Initial Load Forecast was to be supplied from numerous generation sources available to Hydro. Schedule 2 also provides the Base Block Energy, which represents the supply from Muskrat Falls generation to which Hydro is entitled for each operating year of the contract to serve a portion of the NL Native Load. In addition, under the Muskrat Falls PPA, Hydro

⁸ 2024 Actuals have been provided as a comparator throughout this chapter, as 2024 was the first full year in which all Muskrat Falls Assets were in service. Please refer to Schedules C-I through C-V for further information on actuals for 2021 through 2024, along with the forecast for 2025 through 2027.

⁹ The Muskrat Falls PPA Sustaining Capital Deferral Account, which was approved in Board Order No. P.U. 33(2021), captures sustaining capital costs under the Muskrat Falls PPA that relate to both Muskrat Falls and the Labrador Transmission Assets. Additional information is provided in Section 4.3.2. Hydro has proposed the disposition of the deferral account in Chapter 5, Section 5.6.6. In accordance with this deferral account, the sustaining capital costs charged to Hydro through the Muskrat Falls PPA are not directly included in Hydro's supply costs for its 2027 Test Year. Instead, they are proposed to be recovered over a longer period of time. Therefore, they have been removed from this table.

¹⁰ In accordance with Board Order Nos. P.U. 33(2021) and P.U. 4(2022), supply costs associated with Muskrat Falls have been deferred to date in Hydro's Supply Cost Variance Deferral Account.

¹¹ NL Native Load is defined in the Muskrat Falls PPA as the cumulative electricity consumption of customers on the Island Interconnected System, plus associated losses of energy normally incurred in the transmission and distribution of electricity.

1 was also entitled to the energy associated with the Commissioning Period Block¹² and continues to be
2 entitled to the Supplemental Block.^{13,14} During the commissioning period, Hydro received approximately
3 300 GWh of energy for a nominal price of \$1 and was able to displace an estimated \$43 million of fuel at
4 the Holyrood TGS.¹⁵ These fuel savings were for the benefit of customers.

5 If Hydro's load requirements in an operating year exceed the NL Native Load specified in the Muskrat
6 Falls PPA, and Muskrat Falls has additional energy available, Hydro may access Supplemental Block
7 Energy to serve its load requirements at a nominal cost of \$1 per year. Conversely, if reduced customer
8 load requirements result in Hydro's energy usage being lower than the Base Block Energy in an
9 operating year, any unused Base Block Energy is designated as NLH Deferred Energy.¹⁶

10 Figure 4-1 outlines Hydro's energy entitlement framework under the Muskrat Falls PPA. Section 4.2.1
11 further describes NLH Deferred Energy and Hydro's ability to monetize this energy for the benefit of
12 customers.

¹² All energy and capacity associated with the Muskrat Falls plant from time to time during the commissioning period, which means the period commencing at the first power date and ending at the commissioning date. The first power date occurred in December 2020, and Muskrat Falls was commissioned in November 2021.

¹³ The Supplemental Block Energy represents the amount by which the actual NL Native Load in any operating year exceeds the Initial Load Forecast as defined in the Muskrat Falls PPA. Further information on the definition and calculation of Supplemental Block Energy can be found in Article 3.1(b) of the Muskrat Falls PPA.

¹⁴ Hydro is also entitled to Ancillary Services for \$1. Ancillary Services are defined in the Muskrat Falls PPA as services that are necessary to support the transmission of Energy and Capacity from generation to load while maintaining the reliability of a transmission system, including operating reserves, reactive supply, voltage control, blackstart capability, and regulation and frequency response.

¹⁵ This estimated savings assumes that energy deliveries from Muskrat Falls directly displaced energy at the Holyrood TGS and ignores the impact of other system activity.

¹⁶ Further information on NLH Deferred Energy under the Muskrat Falls PPA is included in Section 4.2.1. Further information on the definition and calculation of NLH Deferred Energy can be found in Article 3.1(c) of the Muskrat Falls PPA.

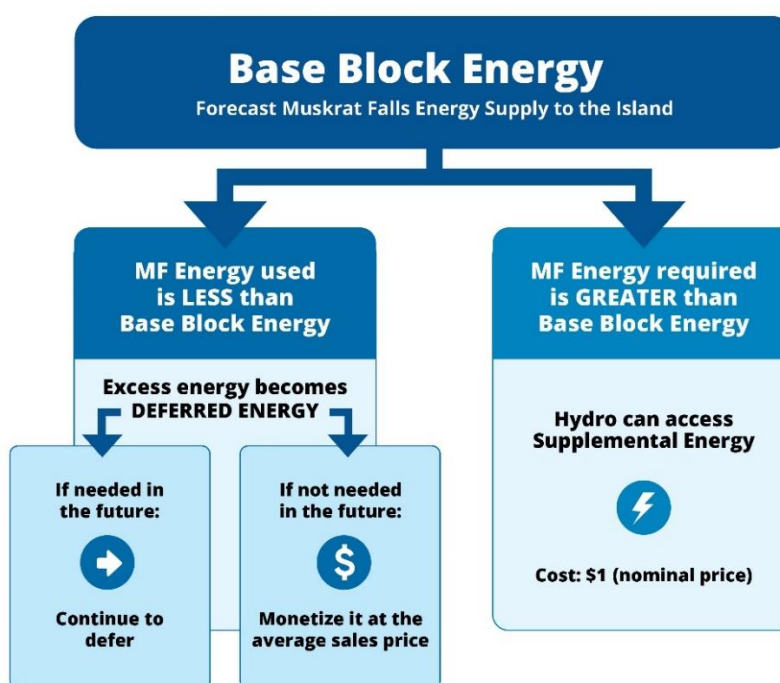


Figure 4-1: Hydro's Energy Under the Muskrat Falls PPA^{17,18}

4.2.1 NLH Deferred Energy

When Hydro's required deliveries of Base Block Energy are less than its entitlement as outlined in Schedule 2 of the Muskrat Falls PPA, the remainder is considered NLH Deferred Energy and is made available for export sales. At the end of each year,¹⁹ Hydro may either defer the resulting NLH Deferred Energy for future use or monetize all or a portion of it²⁰ at the Annual Average Sales Price. The Annual Average Sales Price reflects the net proceeds from Muskrat Falls energy and capacity sales to external markets during the year.²¹

¹⁷ For Hydro to access Supplemental Energy, the NL Native Load must exceed the Initial Load Forecast for the operating year, as defined in the Muskrat Falls PPA.

¹⁸ Hydro currently optimizes the energy produced from the Muskrat Falls plant, as system conditions permit, and delivers as much energy as needed to the Island to serve its customers on the Island Interconnected System, taking into consideration the LIL/Maritime Link restrictions and firm contractual export commitments. Any surplus energy is exported via the Maritime Link or banked at Churchill Falls, to reduce spill from Muskrat Falls and optimize the value of water.

¹⁹ Muskrat Falls is required to provide Hydro with an Annual Energy Report subsequent to the end of the year. This Annual Energy Report provides Hydro with, among other things, the balance of the NLH Deferred Energy. Hydro has the right within a specified period to indicate how much of the NLH Deferred Energy is to be monetized or deemed to have been "sold on Hydro's behalf" as export sales.

²⁰ Not to exceed the volume of Muskrat Falls export sales for that operating year.

²¹ Further information on the calculation of monetized energy and Annual Average Sales Price can be found in Article 4.5(d) of the Muskrat Falls PPA.

Should Hydro forecast the need for additional energy in future years over and above the Base Block Energy, the amount of energy that Hydro had been entitled to and did not use or monetize (i.e., deferred) is available for scheduling in future years to serve this increased load.²²

In the 2027 Test Year, profit associated with NLH Deferred Energy that is forecast to be monetized is provided to customers through inclusion in Hydro’s revenue requirement. Any difference between the test year forecast and actual monetization in any given future year will be included in Hydro’s Supply Cost Variance Deferral Account.²³

In 2024 Actuals, all of Hydro’s deferred energy was monetized. In the 2025 and 2026 Forecasts and the 2027 Test Year, Hydro has assumed that all deferred energy will be monetized. Table 4-2 provides the balance of actual and forecast monetized NLH Deferred Energy or “export sales” in 2024²⁴ to the 2027 Test Year.

Table 4-2: Monetized NLH Deferred Energy (\$ Millions)

2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
73.8	46.0	29.6	38.1

The \$35.7 million decrease in Monetized NLH Deferred Energy in the 2027 Test Year compared to 2024 is driven by a reduction in the forecast volume of deferred energy available for monetization, partially offset by higher forecast export market prices in 2027. The decline in monetized volumes reflects the carryover of NLH Deferred Energy from years prior to 2024 that was fully monetized in 2024. Beginning in 2024, deferred energy is forecast to be fully monetized on an annual basis. The full benefit of Hydro’s monetized NLH Deferred Energy is provided to customers.

²² Under the Muskrat Falls PPA, Hydro is charged for all of its Base Block Energy in the year it is available for use. Therefore, any deferred energy available for use in future years has already been paid for.

²³ Hydro’s existing Supply Cost Variance Deferral Account was approved by the Board effective November 1, 2021, in Board Order Nos. P.U. 33(2021) and P.U. 4(2022). Hydro’s proposal for its Long-Term Supply Cost Variance Deferral Account is included in Chapter 5, Section 5.7, with a proposed effective date of January 1, 2027.

²⁴ The full value of the 2024 monetized energy was deferred in the Supply Cost Variance Deferral Account to the benefit of customers.

4.3 Muskrat Falls PPA Supply Costs

The Muskrat Falls PPA provides for full cost recovery of all costs associated with the Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets through monthly Base Block Payments. These include construction costs, sustaining capital costs, financing costs, which include both interest on debt and return on equity, operating costs, and other types of costs.

Base Block Payments,²⁵ are comprised of the Base Block Capital Costs Recovery and Other Costs for the month, which are explained in further detail in Sections 4.3.1 and 4.3.2.

Table 4-3 shows the components of the total supply costs under the Muskrat Falls PPA for 2024 to the 2027 Test Year.

Table 4-3: Muskrat Falls PPA Supply Costs (\$ Millions)

	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Base Block Capital Costs Recovery	177.9	191.1	204.9	216.1
Other Costs²⁶				
Operating Costs	26.8	28.4	24.6	21.7
Impact and Benefit Agreement	5.9	43.3	13.9	14.2
Water Power Rental	15.5	14.4	16.1	16.4
Other ²⁷	(1.1)	(3.3)	0.7	0.7
Muskrat Falls Sustaining Capital Costs	0.3	4.4	3.7	5.4
LTA Payments ²⁸	48.0	44.7	59.7	49.4
Total Other Costs	95.4	131.9	118.7	107.8
Muskrat Falls PPA Supply Costs Per Agreement	273.3	323.0	323.6	323.9
Muskrat Falls PPA Sustaining Capital Deferral ²⁹	(10.8)	(8.4)	(18.9)	(8.6)
Total Muskrat Falls PPA Supply Costs	262.5³⁰	314.6	304.7	315.3

²⁵ Further information on Base Block Payments can be found in Article 4.2 of the Muskrat Falls PPA.

²⁶ The Muskrat Falls PPA refers to a collection of costs as operating costs. Hydro notes that only a small portion of these costs are operating costs in the traditional sense; therefore, Hydro has titled these “Other Costs.” Other Costs are described in more detail in Section 4.3.2.

²⁷ Other is primarily related to interest earned and operational financing costs.

²⁸ For a further breakdown of Labrador Transmission Assets Payments, please refer to Section 4.3.2.

²⁹ Includes sustaining capital costs for both Muskrat Falls and the Labrador Transmission Assets of \$5.4 million and \$3.2 million, respectively, in the 2027 Test Year.

³⁰ In accordance with Board Order Nos. P.U. 33(2021) and P.U. 4(2022), supply costs associated with Muskrat Falls have been deferred to date in Hydro’s Supply Cost Variance Deferral Account.

4.3.1 Base Block Capital Costs Recovery

The Base Block Capital Costs Recovery is based on the volume of energy delivered and ensures all costs related to the development of the Muskrat Falls Hydroelectric Generating Facility are recovered over the term of the Muskrat Falls PPA. These costs include development capital costs and financing costs incurred related to development capital, including debt and return on equity.³¹ Payments reflect an internal rate of return approach³² to derive a supply price which escalates annually at a rate of 2%.³³

As part of Government's rate mitigation plan, the equity financing of Muskrat Falls and Labrador Transmission Corporation was restructured to facilitate a reduction in the rate of return earned by these entities and charged to Hydro under the Muskrat Falls PPA. The original Muskrat Falls PPA and Generator Interconnection Agreement³⁴ provided for an 8.4% rate of return applied to all equity³⁵ used to finance the projects; however, post-restructuring, this rate of return applies only to the equity which was used to fund the capital costs up to the original budget at sanction. The return on equity used to fund cost overruns was reduced to 3%. In addition, the agreements were updated to remove the return on equity during the construction period and set the earnings of return on equity to start on commissioning of the assets. These measures lowered the cost to Hydro and customers.

The Base Block Capital Costs Recovery was calculated upon full commissioning of the assets, including the LIL, in April 2023, and was, at that time, commercially fixed based on the final determination of the total development capital costs of the asset and financing costs associated with these development capital costs.

³¹ Base Block Capital Costs Recovery includes capital costs associated with the development of the Muskrat Falls Hydroelectric Generating Facility only. Sustaining capital costs associated with these assets are included in Other Costs. In addition, the capital cost recovery and sustaining capital costs of the Labrador Transmission Assets and associated financing costs are included in the Labrador Transmission Assets Payments, which are included in Other Costs and further described in Section 4.3.2.

³² Payment schedule is built to achieve a target rate of return.

³³ The required Base Block Capital Costs Recovery balances by year are provided in Schedule 1 of the Muskrat Falls PPA. The Base Block Capital Costs Recovery is based on Hydro's entitlement to the Base Block Energy as outlined in Schedule 2 of the Muskrat Falls PPA.

³⁴ The Generator Interconnection Agreement is a commercial agreement between Muskrat Falls Corporation and Labrador Transmission Corporation that provides for the recovery of all costs associated with the Labrador Transmission Assets from Muskrat Falls Corporation by Labrador Transmission Corporation. These costs are then recovered from Hydro under the Muskrat Falls PPA. The Generator Interconnection Agreement was originally executed on November 29, 2013, and was replaced with the Amended and Restated Generator Interconnection Agreement on April 14, 2023.

³⁵ Equity financing used to fund the Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets was provided by Government.

As presented in Table 4-3, the Base Block Capital Costs Recovery portion of Hydro’s supply costs under the Muskrat Falls PPA increased by \$38.2 million from 2024 to the 2027 Test Year. This increase is due to a higher volume of energy in 2027 versus 2024, which equates to approximately \$25.7 million, and an increase in the supply price, which escalates 2% annually, equal to approximately \$12.5 million.

4.3.2 Other Costs

Other Costs include all expenses required to operate, maintain, and sustain the Muskrat Falls Hydroelectric Generating Facility and related assets.³⁶ These costs cover routine operating costs, component replacements, administrative and reporting activities, operating financing costs, Impact and Benefit Agreement payments, water power rental payments to Government, and other related items.

The Water Lease Agreement³⁷ is a rental agreement between the province of Newfoundland and Labrador and Muskrat Falls Corporation, granting Muskrat Falls the right to use the Lower Churchill River for power generation. The water power rental costs outlined in Table 4-3 are those which are paid or forecast to be paid to the province under this agreement. According to the agreement, lease payments are equal to \$2.50 per MWh of power generated each year by Muskrat Falls on the Lower Churchill River, escalated annually by Consumer Price Index, resulting in a forecast cost of \$16.4 million in the 2027 Test Year.

Other Costs also include payments to Labrador Transmission Corporation under the Generator Interconnection Agreement, known as Labrador Transmission Assets Payments. Further details on these costs are provided below.

Operating costs and sustaining capital costs associated with the Muskrat Falls Hydroelectric Generating Facility are budgeted by Hydro with the same level of prudence and scrutiny as the regulated operating and capital costs and are required to operate and maintain the assets and to preserve system reliability and safety.³⁸

As presented in Table 4-3, Other Costs in the 2027 Test Year increased by \$12.4 million compared to

³⁶ Muskrat Falls invoices Hydro for Other Costs based on an estimate and then will send a separate quarterly invoice (or credit notice) to Hydro for the difference between the estimated Other Costs (including sustaining capital costs) and the actual Other Costs incurred associated with the Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets.

³⁷ Signed in October 2009 between Government and Nalcor Energy (later assigned to Muskrat Falls Corporation).

³⁸ Please refer to Chapter 2, Section 2.3 for Hydro’s approach to cost management, which is applied organization-wide.

2024. This variance is primarily due to an increase in Impact and Benefit Agreement payments due to an amending agreement³⁹ between Hydro and the Innu Nation and higher Muskrat Falls sustaining capital costs. The increase is partially offset by a decrease in operating costs as a result of lower service provider contract costs.

Sustaining Capital Cost Recovery

The Muskrat Falls PPA requires Hydro to fund the sustaining capital costs of the Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets at the time the expenditures are incurred. Muskrat Falls and Labrador Transmission Assets' sustaining capital costs are included as part of the Other Costs described above.⁴⁰

Recognizing the sustaining capital costs consistent with the timing of these payments under the Muskrat Falls PPA as up-front costs would result in the recovery of the costs of long-life assets in the period incurred, which is inconsistent with inter-generational equity and could contribute to rate volatility. It is also inconsistent with how Hydro recovers sustaining capital invested in its regulated assets. For these reasons, in July 2021, Hydro proposed to establish a regulatory deferral account to deal with the required payments for sustaining capital, the Muskrat Falls PPA Sustaining Capital Deferral Account, which was approved in Board Order No. P.U. 33(2021). Upon payment of sustaining capital costs under the Muskrat Falls PPA, including those associated with the Labrador Transmission Assets, Hydro defers the payments and associated interest.

In its application for the Muskrat Falls PPA Sustaining Capital Deferral Account, Hydro indicated it would present evidence and a proposal for an approach for recovery of the deferral account in its next GRA. This evidence and proposal are included in Chapter 5, Section 5.6.6. Hydro is proposing to amortize the deferral over the period for which the assets are expected to provide service, rather than full cost recovery in the period in which the charges are paid for by Hydro, preventing material rate volatility and providing for matching of cost recovery and the provision of service by the assets. The full balance of the Muskrat Falls PPA sustaining capital costs is deferred in the year, with the amortization of the deferral,

³⁹ Under the amended Impact and Benefit Agreement, Hydro has committed with Muskrat Falls to pay the Innu Nation an annual amount of \$12 million, escalating at the Consumer Price Index, for a term of 50 years, replacing all other Impact and Benefit Agreement payments associated with Muskrat Falls.

⁴⁰ The Labrador Transmission Assets sustaining costs are included in the Labrador Transmission Assets Payments portion of the Other Costs shown in Table 4-3.

in accordance with Hydro’s proposal, included in the 2027 Test Year.

Labrador Transmission Assets Payments

The Labrador Transmission Assets Payments ensure the full recovery of the Labrador Transmission Assets from Muskrat Falls Corporation under the Generator Interconnection Agreement, the costs of which are then passed on to Hydro through the Muskrat Falls PPA. Similar to the Muskrat Falls PPA Base Block Payments, the Labrador Transmission Assets Payments are comprised of Labrador Transmission Assets Capital Cost Recovery Payments and Other Costs.⁴¹

Table 4-4 shows the total Labrador Transmission Assets Payments under the Muskrat Falls PPA, broken down between the Labrador Transmission Assets Capital Cost Recovery and Other Costs for 2024 to the 2027 Test Year.

Table 4-4: Labrador Transmission Assets Payments Under the Muskrat Falls PPA
(\$ Millions)

	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
LTA Capital Cost Recovery	32.7	35.2	37.7	39.7
Other Costs				
Operating Costs	4.9	5.5	6.6	6.3
LTA Sustaining Capital Costs	10.5	4.0	15.3	3.2
Other ⁴²	(0.1)	-	0.1	0.2
Total Other Costs	15.3	9.5	22.0	9.7
Total Labrador Transmission Assets Payments	48.0	44.7	59.7	49.4

The Labrador Transmission Assets Capital Cost Recovery is the mechanism that ensures that all costs related to the development of the Labrador Transmission Assets are recovered over the term of the Muskrat Falls PPA. These costs include development capital costs and financing costs incurred related to development capital, including debt and return on equity. Payments reflect an internal rate of return approach to derive a supply price which escalates annually at a rate of 2%, applied to the Base Block

⁴¹ Similar to the Muskrat Falls PPA, the Generator Interconnection Agreement refers to a collection of costs as operating costs. Hydro notes that only a portion of these costs are operating costs in the traditional sense; therefore, Hydro has titled these “Other Costs.”

⁴² Other includes interest earned and operational financing costs.

Energy as outlined in Schedule 2 of the Muskrat Falls PPA.⁴³ Upon commissioning of the assets, the Labrador Transmission Assets Capital Cost Recovery was calculated and commercially fixed at that time based on the final determination of the total development capital costs of the asset and associated financing costs.

As shown in Table 4-4, the Labrador Transmission Assets Capital Cost Recovery increased by \$7.0 million from 2024 to the 2027 Test Year. This increase is due to a higher volume of energy in 2027 versus 2024, equating to approximately \$4.7 million, and an increase in the supply price, which escalates 2% annually, equal to approximately \$2.3 million.

Other Costs are those required to operate, maintain and sustain the Labrador Transmission Assets, including sustaining activities such as replacements or overhauls of major components, along with asset maintenance, administration and reporting costs. Other Costs also include operating financing costs and other miscellaneous charges.

The Muskrat Falls PPA requires Hydro to fund the sustaining capital costs of the Labrador Transmission Assets at the time the expenditures are incurred, consistent with the treatment of the Muskrat Falls sustaining capital costs. Sustaining capital costs associated with the Labrador Transmission Assets are also included in Hydro's Muskrat Falls PPA Sustaining Capital Deferral Account as described above.

Operating costs and sustaining capital costs associated with the Labrador Transmission Assets are budgeted by Hydro with the same level of prudence and scrutiny as the regulated operating and capital costs and are required to operate and maintain the assets and to preserve system reliability and safety.⁴⁴

Other Costs decreased by \$5.6 million from 2024 to the 2027 Test Year. This variance is primarily due to lower sustaining capital costs forecast to be required.

4.4 Transmission Funding Agreement Supply Costs

Hydro requires the availability and use of the LIL in order to deliver energy from Muskrat Falls to the island of Newfoundland for service to customers on the Island Interconnected System. To do so, Hydro

⁴³ The required payment amounts by year are provided in Schedule 1, Appendix A of the Generator Interconnection Agreement.

⁴⁴ Please refer to Chapter 2, Section 2.3 for Hydro's approach to cost management, which is applied organization-wide.

entered into the Transmission Funding Agreement.⁴⁵ The Transmission Funding Agreement provides for full cost recovery for the construction, sustaining, operating and financing costs of the LIL from Hydro. Transmission Funding Agreement payments consist of rent, operating costs, and \$30,000 per operating year of the contract. Further detail on each of these costs is included in the sections below.

Unlike the Muskrat Falls PPA, the Transmission Funding Agreement payments are not dependent on the volume of energy; they are based on a return on rate base approach⁴⁶ in which the annual cost recovery amount is comprised of return on equity, net interest expense, operating costs, depreciation and other costs. Unlike the Muskrat Falls PPA, Hydro is not required under the Transmission Funding Agreement to finance sustaining capital through upfront payments. Sustaining capital under the Transmission Funding Agreement is charged to Hydro over time, through its monthly payments, which include depreciation and financing costs associated with the sustaining capital.

Table 4-5 shows the breakdown of Transmission Funding Agreement supply costs for 2024 to the 2027 Test Year.⁴⁷

Table 4-5: Transmission Funding Agreement Supply Costs (\$ Millions)

	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Rent				
Return on Equity	207.3	209.0	208.4	207.5
Interest	94.6	102.8	104.3	103.6
Depreciation	113.5	114.3	114.9	115.2
Other ⁴⁸	1.6	1.5	1.3	1.2
Total Rent	417.0	427.6	428.9	427.5
Operating Costs	31.1	33.7	37.9	37.6
Fixed Payment of \$30,000⁴⁹	-	-	-	-
Total Transmission Funding Agreement Supply Costs	448.1⁵⁰	461.3	466.8	465.1

⁴⁵ Costs under the Transmission Funding Agreement are also subject to OC2013-343 as noted in Section 4.1.

⁴⁶ This means that the charges Hydro receives under the agreement cover depreciation and an approved return on the remaining investment in the assets.

⁴⁷ The commissioning of the LIL occurred after Hydro's 2017 GRA, and therefore, there are no Transmission Funding Agreement costs included in Hydro's 2019 Test Year for comparative purposes.

⁴⁸ Other includes costs to administer the LIL Limited Partnership and taxes.

⁴⁹ The fixed payment of \$30,000 is included in the total Transmission Funding Agreement Supply Costs; however, it does not show in the table due to rounding.

⁵⁰ In accordance with Board Order Nos. P.U. 33(2021) and P.U. 4(2022), supply costs associated with the Transmission Funding Agreement have been deferred to date in Hydro's Supply Cost Variance Deferral Account.

4.4.1 Rent

Rent under the Transmission Funding Agreement consists of a number of components: return on equity, net interest expense, depreciation of both the original capital costs and sustaining capital, expenses to administer the LIL Limited Partnership,⁵¹ and taxes.

Construction costs and ongoing sustaining capital associated with the LIL are financed through debt and equity. The interest portion of the rent payment relates to financing costs associated with outstanding debt balances. The return on equity in the Transmission Funding Agreement reflects the return on equity approved by the Board for privately-owned regulated electric utilities in Newfoundland and Labrador, which is currently 8.60%.⁵² As a result, changes in the allowed return on equity of privately-owned utilities in Newfoundland and Labrador result in a change in the annual cost recovery amount in the Transmission Funding Agreement.

Annual depreciation on the original capital costs of the LIL is calculated by taking the undepreciated capital costs divided by the remaining service life of the LIL. The service life of the LIL is 50 years.⁵³

A significant portion, or 90%, of the rent payments under the Transmission Funding Agreement are commercially fixed upon commissioning of the LIL, including the return on equity⁵⁴ and depreciation associated with the original capital costs, along with interest related to debt financing.

Annual depreciation of the sustaining capital costs of the LIL is calculated by taking the undepreciated sustaining costs divided by the remaining service life of the LIL, averaged as appropriate, consistent with regulatory practice.⁵⁵ Sustaining capital costs associated with the LIL are budgeted with the same level of

⁵¹ Costs to administer the LIL Limited Partnership include but are not limited to expenditures such as audit fees, administrative labour and operational financing costs.

⁵² More specifically, the Transmission Funding Agreement, Article 3.9(a) states if during a fiscal year there is only one privately-owned regulated electrical utility in Newfoundland and Labrador, the return on equity shall be equal to the rate of after tax-return on equity approved by the Board in respect of such utility for such fiscal year and, if during a fiscal year there is more than one privately-owned regulated electrical utility in Newfoundland and Labrador, the return on equity shall be the average of the rates of after-tax return on equity approved by the Board in respect of all such utilities for such fiscal year.

⁵³ The service life of the LIL is determined by the commercial contracts, is linked to cost recovery and not necessarily equal to the actual estimated useful life of the asset.

⁵⁴ With the exception of changes in the rate as approved by the Board and described above.

⁵⁵ Hydro anticipates that a deferral account will be required in the future as major units of property are replaced later in the term of the Transmission Funding Agreement with assets that have useful lives that significantly exceed the remaining term of the contract or the remaining service life of the LIL.

prudence and scrutiny as the regulated capital costs and are required to sustain the assets to preserve system reliability and safety.⁵⁶

As shown in Table 4-5, Rent increased by \$10.5 million from 2024 to the 2027 Test Year. This increase is primarily related to higher bank interest earned in 2024, which is net against the financing costs charged to Hydro.

4.4.2 Operating Costs

Operating costs, as reported in Table 4-5, are those necessary to operate and maintain the LIL, along with administration and reporting costs.⁵⁷ Transmission Funding Agreement operating costs are budgeted by the organization with the same level of prudence and scrutiny as the regulated operating costs and are required to operate and maintain the assets and to preserve system reliability and safety.

Transmission Funding Agreement operating costs increased by \$6.5 million from 2024 to the 2027 Test Year. This variance is primarily due to an increase in operating labour costs during the period, higher capitalized labour in 2024 than forecast for the 2027 Test Year and an increase in contract costs due to the transition to operations, which was ongoing in 2024.⁵⁸

4.5 Summary

Muskrat Falls supply costs form one of the most significant components of Hydro's 2027 Test Year revenue requirement. These costs are driven primarily by the contractual structures of the Muskrat Falls PPA and the Transmission Funding Agreement. Together, these agreements ensure full recovery of initial capital, financing, sustaining capital, and operating costs associated with the Muskrat Falls Project. Although OC2013-343 guarantees the recovery of these costs and Government's rate mitigation framework dictates the degree to which they can be reflected in customer rates, Hydro manages these costs as it would for any regulated cost, placing importance on transparency and prudent internal cost management.

⁵⁶ Please refer to Chapter 2, Section 2.3 for Hydro's approach to cost management, which is applied organization-wide.

⁵⁷ Similar to the charges of Other Costs under the Muskrat Falls PPA, LIL Operating Corporation will send a separate quarterly invoice (or credit notice) to Hydro for the difference between the estimated operating costs and the actual costs incurred associated with the LIL.

⁵⁸ Certain scopes of work performed under contract in 2024 were related to construction punch list items and were therefore included in capital costs.

The Muskrat Falls supply costs fall into two broad categories. Certain costs are commercially fixed, arising from statutory or contractual requirements and are associated with the original construction costs. Other costs are determined by Hydro and subject to active management in the same manner as regulated costs. These costs are unavoidable, not discretionary and include costs such as operating costs and sustaining capital. They are required to operate and maintain the assets and are necessary to maintain system reliability, safety and Hydro's ability to serve its customers.

Chart 4-1 outlines the portion of the 2027 Test Year Muskrat Falls PPA and Transmission Funding Agreement supply costs which are considered commercially fixed versus those which are operationally managed.⁵⁹

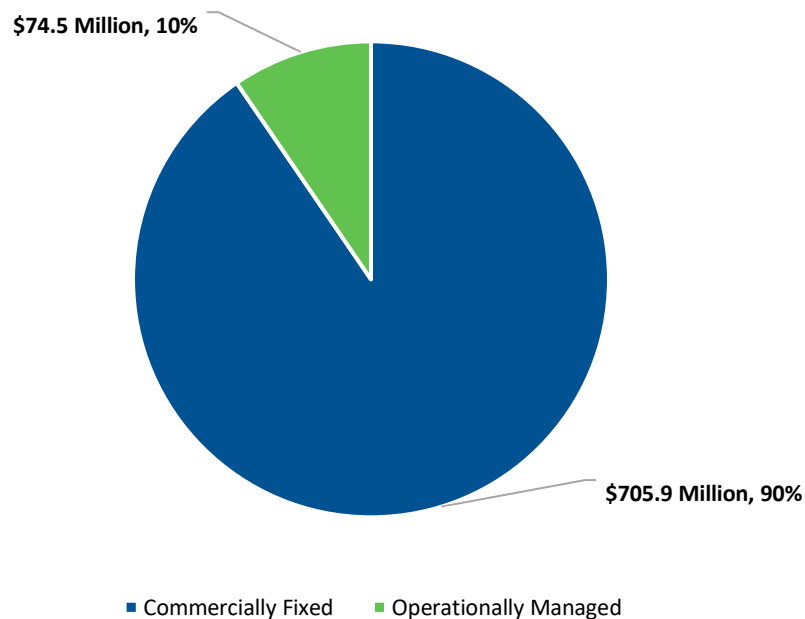


Chart 4-1: Muskrat Falls Supply Costs

As shown in Chart 4-1, approximately 90% of Hydro's costs under the Muskrat Falls PPA and Transmission Funding Agreement are commercially fixed and are unable to be changed or influenced by Hydro.

⁵⁹ Operationally managed costs are those related to operating costs and sustaining capital costs. These costs may have minimal variation year over year, which would primarily be driven by sustaining capital requirements.

1 Operationally managed costs, which are determined by Hydro, are primarily operating costs and
2 sustaining capital costs and represent about 10% of the overall Muskrat Falls supply costs. These costs
3 are budgeted by Hydro with the same level of prudence and scrutiny as the regulated operating and
4 capital costs and are required to operate and maintain the assets and to preserve system reliability and
5 safety.

6 Hydro has achieved savings in operating costs associated with the Muskrat Falls Assets from those
7 initially estimated for the base year or the first full year of operations of the assets. Estimated operating
8 costs for the base year, or first full year of operations, provided to the Board as part of the Rate
9 Mitigation Options and Impacts Reference proceeding⁶⁰ were \$83.1million, adjusted for inflation to 2024
10 dollars. When compared to the actual operating costs for 2024, the first full year of operation of the
11 assets, of \$62.8 million,⁶¹ operating costs for the Muskrat Falls Assets have decreased by \$20.3 million or
12 24%.

13 Hydro manages all areas of its operation, both regulated and non-regulated, to the same standard,
14 applying an operational philosophy of *Good Utility Practice* and in line with its mandate to provide least-
15 cost, reliable service in an environmentally responsible manner.

⁶⁰ Please refer to Nalcor's response to the request for information PUB-Nalcor-050 of the Rate Mitigation Options and Impacts Reference proceeding.

⁶¹ Muskrat Falls Operating Costs (\$26.8) + Labrador Transmission Assets Operating Costs (\$4.9) + LIL Operating Costs (\$31.1) = \$62.8.

Chapter 5

Revenue Requirement



Chapter 5: Revenue Requirement

5.1 Overview

In accordance with Section 80 of the *Act* and Section 3(a)(iii) of the *EPCA*, rates charged by Hydro should provide it with the opportunity to earn a fair, just, and reasonable rate of return to achieve and maintain a sound credit rating in the financial markets of the world.¹ Sound financial performance is necessary to ensure Hydro's ability to deliver the least-cost, reliable, environmentally responsible electrical service to its customers.

Hydro's current base rates were set effective October 1, 2019, based on a 2019 Test Year,² and under these rates, Hydro is forecast to earn a 2027 return on rate base of 3.49%,³ below its approved return on average rate base of 5.45% in a range of 5.25% to 5.65% for ratemaking purposes.⁴ Hydro's revenue requirement is generally comprised of the return on rate base and other reasonable costs, including operating costs, fuels, power purchases, other supply costs and depreciation; however, for the 2027 Test Year, the revenue requirement includes Muskrat Falls supply costs⁵ and is calculated net of rate mitigation funding⁶ that offsets a portion of Hydro's costs that would otherwise be recovered through customer rates. Based on this framework, Hydro proposes a 2027 Test Year return on rate base of 4.88%,⁷ derived from an embedded cost of debt of 4.05%⁸ and a return on equity of 8.60%.⁹

As part of its 2027 GRA, Hydro is requesting approval by the Board of the following proposals for the purposes of calculation of the 2027 Test Year as outlined in Schedule D-I:

- A 2027 Test Year revenue requirement of \$797.7 million,

¹ In OC2009-063, Government directed that: (i) in calculating the return on rate base for Hydro, the same rate of return on equity would be set for Hydro as was last set for Newfoundland Power; (ii) Hydro would earn return on equity on its entire rate base, including amounts related to its rural assets; and (iii) Hydro would be permitted to have a proportion of equity in its capital structure up to a maximum of the same as is approved for Newfoundland Power.

² Hydro's revenue requirement analysis for the 2019 Test Year through the 2027 Test Year is provided in Schedule D-I.

³ Hydro's 2027 Test Year return on rate base is found in Schedule D-II. For return on rate base under existing rates, please refer to Schedule D-III.

⁴ Approved rate of return from Hydro's 2017 GRA was 5.43%; however, this was subsequently updated to 5.45% effective July 1, 2025, in accordance with Board Order No. P.U. 10(2025).

⁵ Further information on Muskrat Falls supply costs is included in Chapter 4.

⁶ Further information on rate mitigation is included in Section 5.2.7.

⁷ Please refer to Schedule D-II, p. 4.

⁸ Please refer to Schedule D-IV.

⁹ As approved in Board Order No. P.U. 10(2025).

- A 2027 Forecast average rate base of \$2,802.1 million; and
- A rate of return on rate base of 4.88% in a range of 4.68% to 5.08%.

5.2 2027 Test Year Revenue Requirement

The components of the 2019 and 2027 Test Year revenue requirements are provided in Table 5-1.

Table 5-1: Components of Revenue Requirement (\$ Millions)^{10,11}

	2019 Test Year	2027 Test Year
Operating Costs ¹²	136.9	156.4
Fuels	219.9	106.3
Muskrat Falls Supply Costs ¹³	-	780.4
Power Purchases ¹⁴	81.7	66.9
Depreciation and Accretion ¹⁵	85.8	117.7
Other Adjustments ¹⁶	(7.0)	(64.7)
Rate Mitigation	-	(502.0)
Return on Rate Base	125.8	136.7
Total Revenue Requirement	643.0	797.7

The primary drivers of the \$154.7 million increase in revenue requirement from the 2019 Test Year are Muskrat Falls supply costs, partially offset by rate mitigation and a decrease in fuel costs. The rate mitigation plan reduces the revenue requirement to just over 60%¹⁷ of forecast costs to supply customers. The \$797.7 million revenue requirement will be recovered through Hydro's proposed customer rates. Details on Hydro's proposed rates are provided in Chapter 6.

¹⁰ Please refer to Schedule D-I.

¹¹ Numbers may not add due to rounding.

¹² Operating costs include labour and other operating and maintenance costs associated with Hydro's regulated operations.

¹³ OC2013-343 and the Muskrat Falls Project Exemption Order stipulate that all of these costs are recoverable through Island Interconnected System customer rates without disallowance or reduction.

¹⁴ Excludes power purchases for the use of Muskrat Falls in Labrador, which are included within net export revenue in other adjustments. Please refer to Section 5.2.3.

¹⁵ Includes accretion of asset retirement obligation.

¹⁶ Other adjustments include net export revenue, transmission tariff revenue, other revenue, CIAC revenue and capital asset cost of service exclusions. For further information, please refer to Section 5.2.6.

¹⁷ Total costs to serve customers is equal to revenue requirement with rate mitigation added back (\$797.7 + \$502.0 = \$1,299.7). Rate Mitigation (\$797.7) / Total Cost to Serve Customers (\$1,299.7) = 61%.

5.2.1 Fuel Costs

Fuel costs include the cost of No. 6 fuel used at the Holyrood TGS, fuel for Hydro’s CT fleet,¹⁸ and diesel generator fuel. The components of the fuel costs category are provided in Table 5-2.

Table 5-2: Fuel Costs (\$ Millions)

	2019	2027
	Test Year	Test Year
No. 6 and Other	194.7	65.0
Diesel and CT	25.2	41.3
Total Fuel Costs	219.9	106.3

Fuel costs have decreased by more than 50% from the 2019 Test Year. The primary driver of the \$113.6 million decrease in the 2027 Test Year fuel costs compared to the 2019 Test Year is lower No. 6 fuel costs. No. 6 fuel costs decreased by \$129.7 million primarily as a result of the commissioning of the Muskrat Falls Assets, allowing for materially lower thermal generation at Holyrood TGS to be replaced by clean hydro generation from Muskrat Falls. The 2027 Test Year includes 809 Mbbls¹⁹ of No. 6 fuel and 455 GWh of Holyrood TGS production compared to 1,835 Mbbls in the 2019 Test Year and 1,070 GWh of production.²⁰ Hydro also notes that, in the 2019 Test Year, 482 GWh of off-Island purchases were planned, including 341 GWh of Recapture Energy from Churchill Falls, which was forecast to be delivered over the LIL to the Island. This created fuel savings in the 2019 Test Year of approximately \$87.6 million,²¹ meaning the reduction in fuel forecast in the 2027 Test Year is even more significant when compared to typical Holyrood TGS operating levels prior to commissioning of the Muskrat Falls Assets. The decrease in No. 6 fuel is partially offset by an increase in diesel and CT fuel costs of \$16.1 million due to an increase in both volume and price. Volume is expected to increase as a result of an extended outage of Bay d’Espoir Units 5 and 6 due to the planned replacement of Penstock 3, resulting in a higher level of thermal generation support.

¹⁸ Hydro’s CT fleet includes the Holyrood CT, the Stephenville e GT, the Hardwoods GT and the Happy Valley-Goose Bay GT.

¹⁹ 1 Mbbls is equivalent to 1,000 barrels of No. 6 fuel.

²⁰ Further discussion around fuel variances is included in Chapter 1, Section 1.3.2.

²¹ 482 GWh using a 2019 Test Year conversion factor of 583 at the 2019 Test Year fuel price of \$105.90/bbl. For further information on fuel usage and conversion factors associated with the period of 2019 through to the 2027 Test Year, please refer to Schedule A-V.

5.2.2 Muskrat Falls Supply Costs

Muskrat Falls supply costs are \$780.4 million²² in the 2027 Test Year, reflecting the inclusion of costs associated with the assets that are now fully commissioned and in service. In contrast, there were no Muskrat Falls supply costs in the 2019 Test Year. Payments by Hydro under the Muskrat Falls PPA commenced in November 2021, when the Muskrat Falls Hydroelectric Generating Facility was fully commissioned.²³ Payments by Hydro under the Transmission Funding Agreement commenced once LIL was commissioned in April 2023. Approximately 39%²⁴ of Hydro's costs, including Muskrat Falls supply costs, are mitigated in accordance with Government's rate mitigation plan, meaning a significant portion will not be recovered from customers through electricity rates. Additional detail on the composition and drivers of Muskrat Falls supply costs is provided in Chapter 4. Additional detail on rate mitigation is provided in Section 5.2.7.

5.2.3 Power Purchases

Power purchases include costs of supply from Exploits generation, wind, off-Island and other sources as outlined in Table 5-3.

Table 5-3: Power Purchases (\$ Millions)

	2019 Test Year	2027 Test Year
Exploits Generation ²⁵	30.3	30.2
Wind ²⁶	14.1	15.7
Off-Island ²⁷	14.3	-
Other ²⁸	23.0	21.0
Total Power Purchases	81.7	66.9

²² Although OC2013-343 and the Muskrat Falls Project Exemption Order stipulate that all costs are recoverable through Island Interconnected System customer rates without disallowance or reduction, Government's rate mitigation plan mitigates a significant portion of these costs.

²³ Hydro notes that Commissioning Period Energy, purchased by Hydro for \$1, was produced by Muskrat Falls and delivered to the Island over the LIL in the period prior to the commencement of payments by Hydro under the Muskrat Falls PPA. In addition, as noted in Section 5.2.1, Recapture Energy from Churchill Falls was forecast to be delivered to the Island using the LIL in the 2019 Test Year. Therefore, Hydro and customers received benefits from the Muskrat Falls Assets during the commissioning period, prior to the commencement of power purchases under the commercial agreements.

²⁴ Total costs to serve customers is equal to revenue requirement with rate mitigation added back (\$797.7 + \$502.0 = \$1,299.7). Rate Mitigation (\$502.0) / Total Cost to Serve Customers (\$1,299.7) = 39%.

²⁵ Includes Star Lake.

²⁶ Includes Fermeuse and St. Lawrence.

²⁷ Includes LIL Recapture Energy and Maritime Link imports.

²⁸ Other includes power purchases from CBPP, purchases from Hydro-Québec, and non-utility generators, etc.

The primary driver of the \$14.8 million decrease in the 2027 Test Year power purchases compared to the 2019 Test Year is lower off-Island power purchases of \$14.3 million due to imports over the Maritime Link, which were forecast in the 2019 Test Year but are not forecast for 2027.²⁹

5.2.4 Operating Costs

Operating costs in the 2027 Test Year of \$156.4 million are \$19.5 million higher than the 2019 Test Year of \$136.9 million, which is primarily a reflection of labour cost increases and market-driven increases in the cost of goods and services. As discussed in Chapter 2, Hydro has achieved reductions in real dollars totalling approximately \$8.0 million in non-labour costs and \$9.0 million in labour costs over 2019 Test Year levels.³⁰ The majority of these savings reflect targeted actions to manage cost and align with stakeholder expectations. Additional information on operating cost variances is contained in Chapters 2 and 3.

5.2.5 Depreciation and Accretion

The components of depreciation and accretion are provided in Table 5-4.

Table 5-4: Depreciation and Accretion (\$ Millions)

	2019 Test Year	2027 Test Year
Depreciation	85.4	116.6
Accretion of Asset Retirement Obligation	0.4	1.1
Total Depreciation and Accretion	85.8	117.7

In the 2027 Test Year, depreciation and accretion is \$31.9 million higher than in the 2019 Test Year. The primary driver of this increase is growth in asset base since the 2019 Test Year, as a result of Hydro's capital program, including projects related to the Holyrood TGS, which are depreciated at an accelerated

²⁹ Since the 2019 Test Year was compiled, it was determined that planning for imports over the Maritime Link is not a feasible option. Transmission paths to gain access to potential markets are largely committed, and neighbouring jurisdictions do not have surplus capacity to export. Therefore, Hydro does not include any long-term plan for Maritime Link imports for production planning purposes, and they are not included in the 2027 Test Year. This confirmation does not preclude opportunities on a short-term (spot market) basis for firm capacity or non-firm energy to meet capacity or energy requirements for the Island Interconnected System.

³⁰ Please refer to Chapter 2, Section 2.3.

rate given its planned retirement. This increase has been partially offset by reduced depreciation rates proposed in the depreciation study.

Depreciation Methodology

Hydro engaged Concentric, a third-party consultant, to conduct a comprehensive depreciation study relating to the plant in service as of December 31, 2022, with a technical update to December 31, 2024. The studies are provided as Exhibit 7 and Exhibit 8, respectively.

The depreciation study recommends the use of updated estimates of the service lives of assets.³¹ The combined impact of these changes on Hydro's revenue requirement for the 2027 Test Year is a decrease of \$7.3 million from the 2019 Test Year.

As part of this application, Hydro is requesting Board approval of the depreciation rates and methodology recommended in the 2023 Depreciation Study and 2024 Technical Update for inclusion in the determination of customer rates.

³¹ Annual depreciation accrual rates are summarized in Tables 1, 1A, and 1B in Section 5 of the 2024 Technical Update, provided as Exhibit 8.

5.2.6 Other Adjustments

The components of other adjustments are provided in Table 5-5.

Table 5-5: Other Adjustments (\$ Millions)³²

	2019	2027
	Test Year	Test Year
CIAC Revenue	(1.8)	(2.3)
Other Revenue ³³	(2.1)	(3.4)
Transmission Tariff Revenue	-	(18.3)
Net Export Revenue ³⁴	-	(40.2)
Capital Asset Cost of Service Exclusions ³⁵	(3.1)	(0.4)
Total Other Adjustments	(7.0)	(64.7)

In the 2027 Test Year, other adjustments is a credit balance which increased by approximately \$57.7 million in comparison to the 2019 Test Year. The primary driver of the increase is net export revenue of \$40.2 million, which primarily relates to the monetization of Hydro's deferred energy under the Muskrat Falls PPA. Further information on Muskrat Falls supply costs and the monetization of deferred energy is included in Chapter 4.

Also contributing to the variance is an increase in transmission tariff revenue of \$18.3 million. 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. This transmission tariff is based on the published rate and is paid to the NLSO.³⁶ The transmission tariff revenue generally relates to the export of Muskrat Falls energy over the Maritime Link, as Hydro's transmission assets are required to be

³² Numbers may not add due to rounding.

³³ Other revenue consists of pole attachment and sundry revenue in the 2019 Test Year. In the 2027 Test Year, other revenue consists of pole attachment, greenhouse gas credit and sundry revenue. The province's *Management of Greenhouse Gases Act* came into effect on January 1, 2019, and 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 industrial facilities in the province. There were no forecast or actual sales of these credits in 2019; however, since that time, Hydro has completed sales of performance credits on an annual basis, and the revenue has been deferred in the Supply Cost Variance Deferral Account for the benefit of customers. Hydro is forecasting greenhouse gas credit sales in the 2027 Test Year of \$1.3 million.

³⁴ Net export revenue includes Hydro's monetization of deferred energy under the Muskrat Falls PPA. For further information, please refer to Chapter 4, Section 4.2.1. In addition, it includes Hydro's net export profit from the use of Muskrat Falls energy in Labrador to create incremental recapture for export.

³⁵ Capital asset cost of service exclusions is the reduction of depreciation for capital assets that have been excluded from recovery in rate base.

³⁶ NLSO rates and rate methodology were approved on an interim basis in Board Order No. P.U. 3(2018) in accordance with OC2017-380. Hydro will file an application for permanent rates and rate methodology subsequent to the conclusion of the GRA.

used to facilitate the delivery of this energy. There was no forecast transmission tariff revenue in 2019 as the Muskrat Falls Assets were not forecast to be commissioned at that time.

5.2.7 Rate Mitigation

In recognition of the affordability impacts of the Muskrat Falls Project on customers, Government committed to mitigating rate impacts. In May 2024, Government finalized its rate mitigation plan and issued supporting OCs^{37,38} directing Hydro with respect to the structure of future rate applications and sources of funding.

Notwithstanding the provisions of OC2013-343 and the Muskrat Falls Project Exemption Order, which provide that all Muskrat Falls Project costs are recoverable from Island Interconnected System customers without disallowance or reduction and are not subject to prudence review by the Board, Government's rate mitigation plan has the effect of mitigating a significant portion of Hydro's costs. While the Muskrat Falls supply costs remain outside the Board's jurisdiction for review or prudence assessment, Hydro has provided information on the costs in Chapter 4 in the interest of transparency and accountability.

Government's Rate Mitigation Plan

The rate mitigation framework is supported by federal and provincial financing arrangements. On July 28, 2021, the Government of Canada and Government announced an agreement in principle for federal financing support and later signed term sheets in February 2022. The arrangements include a \$1 billion investment in the LIL in the form of a convertible debenture³⁹ and a third federal loan guarantee related to the Muskrat Falls Hydroelectric Generating Facility and the Labrador Transmission Assets, along with capital restructuring of Muskrat Falls Corporation and Labrador Transmission Corporation.⁴⁰ These measures significantly contribute to rate mitigation by reducing financing costs and providing an additional source of funding through the convertible debenture.

³⁷ Government of Newfoundland and Labrador, *Order in Council OC2024-062*, May 7, 2024.

³⁸ Government of Newfoundland and Labrador, *Order in Council OC2024-063*, May 7, 2024.

³⁹ Drawings on the convertible debenture are required to be used for the purpose of rate mitigation funding. Drawings are permitted to be a maximum of \$150 million per year until the debenture is fully drawn. As the debenture is drawn, funding is transferred to Hydro's regulated operating segment for the purpose of rate mitigation. The convertible debenture is recorded in one of Hydro's non-regulated subsidiaries, LIL (2021) Limited Partnership, and is repayable commencing in 2042.

⁴⁰ The capital restructuring of Muskrat Falls reduced the rate of return under the Muskrat Falls PPA, lowering the costs charged to Hydro.

Following the federal financing announcements, Hydro and Government worked to finalize the remaining elements of the rate mitigation plan. This work concluded in May 2024 with the issuance of supporting OCs. OC2024-062⁴¹ directs Hydro to structure each rate application such that retail rate increases attributable to Hydro for Island Interconnected System Domestic customers are targeted at 2.25% per year through 2030. The Order further directs that any additional funding required to mitigate costs for Island Interconnected System customers in order to achieve the targeted rate increases be sourced from Hydro to the extent possible. The Order also required that Hydro retire the balance of the 2023 Supply Cost Variance Deferral Account over a three-year period beginning in 2024.⁴²

Hydro's Supply Cost Variance Deferral Account was approved in Board Order No. P.U. 33(2021), with the definition of the account reflecting the Board's directions in Board Order No. P.U. 4(2022).⁴³ The purpose of the Supply Cost Variance Deferral Account is to address material changes in system costs associated with the integration of Muskrat Falls Assets into the provincial electricity system. The account allows Hydro to defer, amongst other supply costs and revenue variances, the difference between Muskrat Falls Project costs incurred and those reflected in customer rates. The Supply Cost Variance Deferral Account definition also permits Hydro to apply rate mitigation funding received to reduce balances otherwise recoverable from customers. Rate mitigation funding applied against the balance owing in Hydro's Supply Cost Variance Deferral Account to December 31, 2024, and that which is forecast for 2025 through 2027, is provided in Table 5-6.⁴⁴ Beginning January 1, 2027, any variances from test year forecasts are proposed to be deferred in Hydro's Long-Term Supply Cost Variance Deferral Account, as outlined in Section 5.7.

The average annual rate mitigation funding required from Hydro's internal sources⁴⁵ is estimated to be upwards of \$350 million per year.⁴⁶

⁴¹ OC2024-063, issued on the same date, directed the Board of Directors of Nalcor that any additional funding required for Hydro to mitigate the Lower Churchill Project costs or to retire the 2023 Supply Cost Variance Deferral Account balance of \$271 million be through Nalcor's own sources.

⁴² As reported in the Supply Cost Variance Deferral Account Monthly Report for March 2026, the 2023 balance of \$271 million has been retired per Government direction.

⁴³ The Supply Cost Variance Deferral Account definition was last approved in Board Order No. P.U. 34(2023).

⁴⁴ The estimated timing of rate mitigation funding transfers may cause fluctuations in the balance on a year-over-year basis. Actual timing may differ from the forecast.

⁴⁵ Excluding Government of Canada Convertible Debenture.

⁴⁶ The estimated average of rate mitigation funding from internal sources is calculated using 2024 Actuals, 2025 and 2026 Forecast, and 2027 Test Year.

Table 5-6: Rate Mitigation Funding (\$ Millions)

	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast	2027 Test Year
Hydro's Internal Sources	-	90.0	554.4	440.9	352.0
Government of Canada Convertible Debenture	144.7	150.3	150.0	150.0	150.0
Government Grant	190.4	-	-	-	-
Total Rate Mitigation Funding	335.1	240.3	704.4	590.9	502.0

Implementation of Government's Rate Mitigation Plan

Implementation of Government's rate mitigation plan in customer rates commenced with the first rate change becoming effective on August 1, 2024.⁴⁷ This was followed by the implementation of rate mitigation for Hydro's Island Industrial Customers in their rate update effective January 1, 2025. In October 2024, Hydro filed its Implementation of the Rate Mitigation Plan Report with the Board, as requested. Following completion of the regulatory process, the Board accepted the report as filed on April 1, 2025.⁴⁸

2027 Test Year Rate Mitigation

Government's rate mitigation plan has been incorporated into the updated Cost of Service Study provided as Schedule F. In the 2027 Test Year, revenue requirement has been calculated based on the cost to supply customers on the Island Interconnected System, including from the Muskrat Falls Assets, and includes the impact of rate mitigation. Customer rates on the Island Interconnected System are then set in accordance with the rate increases targeted in Government's rate mitigation plan. In this context, rate mitigation represents the amount of revenue requirement that is not recovered through customer rates due to the application of the targeted rate. Hydro's 2027 Test Year includes \$502.0 million in rate mitigation applied to offset supply costs.⁴⁹

⁴⁷ Hydro's application for July 1 rates was originally filed on June 19, 2024, with an effective date of July 1, 2024. On July 10, 2024, the Board issued Order No. P.U. 16(2024) directing Newfoundland Power to file a revised Rate Stabilization Adjustment. Hydro's revised application with an effective date of August 1, 2024, was filed on July 22, 2024, and was approved in Board Order No. P.U. 15(2024).

⁴⁸ "Implementation of the Rate Mitigation Plan Report," Newfoundland and Labrador Hydro, October 22, 2024. Provided as Exhibit 3.

⁴⁹ In Hydro's revenue requirement, for the purpose of rate design, the timing of rate mitigation funding has been aligned with the associated Muskrat Falls supply cost payments. Actual timing of rate mitigation funding may differ.

Overall, Government’s rate mitigation plan materially limits the rate impacts that would otherwise result from full recovery of Hydro’s costs through customer rates. Through the combined use of federal financing support, provincial direction, Hydro-sourced rate mitigation funding, and Board approval of deferral accounting mechanisms, the plan provides for rate stability for customers through 2030 while ensuring appropriate transparency of the associated costs and treatment within Hydro’s regulatory framework.

5.3 Average Rate Base

The components of the average rate base are provided in Table 5-7

Table 5-7: Average Rate Base (\$ Millions)^{50,51}

	2019	2027
	Test Year	Test Year
Unadjusted Capital Assets – Average	2,133.4	2,463.3
Deductions:		
Average Net Assets Excluded from Rate Base	(11.5)	(6.2)
Total Average Capital Assets in Rate Base	2,121.9	2,457.1
Other Components of Rate Base		
Working Capital Allowance – Muskrat Falls Related	-	115.1
Working Capital Allowance – Other	2.0	1.6
Fuel Inventory ⁵²	57.2	68.0
Materials and Supplies ⁵³	32.9	44.7
Deferred Charges	103.3	115.6
Total Other Components	195.4	345.0
Total Average Rate Base	2,317.3	2,802.1

In the 2027 Test Year, the average rate base is \$484.7 million higher than in the 2019 Test Year. This is primarily a result of an increase in capital assets and working capital requirements.

⁵⁰ Please refer to Schedule D-II, p. 4.

⁵¹ Numbers may not add due to rounding.

⁵² Fuel inventory is comprised of a 13-month average of No. 6 fuel, diesel, and CT fuel inventories.

⁵³ Materials and supplies include consumables, inventory, and critical spares that are used by Hydro for the construction and maintenance of operational assets and equipment.

5.3.1 Capital Assets

The increase in average capital assets in rate base from the 2019 Test Year to the 2027 Test Year of \$335.2 million is primarily due to capital additions during the same period. Major additions include turbine and valve overhauls on the thermal units at the Holyrood TGS and Bay d’Espoir Penstock 1 life extension.

5.3.2 Working Capital Allowance

Hydro’s working capital allowance reflects the average amount of capital provided by investors to finance operations between the time expenditures are made to provide service to customers and the time payment is received from customers for that service.

A summary of the working capital allowance is provided in Table 5-8.

Table 5-8: Working Capital Allowance (\$ Millions)⁵⁴

	2019 Test Year	2027 Test Year Muskrat Falls Related	2027 Test Year Other
Working Capital Factor:			
Revenue Lag Days	38.5	44.5	38.3
Less: Expense Lag Days	29.9	(7.8)	29.5
Net Lag Days	8.6	52.2	8.8
Working Capital Factor % (Net Lag/365 Days)	2.4%	14.3%	2.4%
Working Capital Allowance:			
Total Cash Operating Expenses	219.2	806.0	222.3
Working Capital Factor %	2.4%	14.3%	2.4%
Working Capital Allowance	5.2	115.3	5.4
HST Adjustment	(3.1)	(0.2)	(3.8)
Total Working Capital Allowance	2.0	115.1	1.6

Hydro has presented its 2027 Test Year working capital allowance, separated between that which is related to Muskrat Falls supply costs and related transactions, and other working capital. The 2027 Test Year working capital allowance is consistent with the 2019 Test Year when normalized for Muskrat Falls

⁵⁴ Numbers may not add due to rounding.

supply costs. The introduction of power purchases from Muskrat Falls under the PPA and the Transmission Funding Agreement, which were not present in the 2019 Test Year, has a significant impact on Hydro's working capital calculation.

Under the Muskrat Falls PPA and Transmission Funding Agreement, Hydro is required to pay for power purchases on the first day of the month to which the service relates (i.e., payment is made in advance of delivery and consumption). In contrast, revenues associated with this energy are recovered from customers through the normal billing cycle, or through rate mitigation funding, with cash receipts assumed to occur in the subsequent month. The timing of rate mitigation funding is assumed to be consistent with customer payments for the purpose of the calculation of working capital allowance.⁵⁵

As these power purchase payments represent a new and significant cash outflow not previously incurred, this has created an ongoing working capital requirement to bridge the timing difference between these supplier payments and customer collections or receipt of rate mitigation funding.

Also contributing to the increase is the timing of receipt of payment for Hydro's monetized deferred energy under the Muskrat Falls PPA. Monetized deferred energy is recorded in December; however, it is not settled until the first quarter of the following year, in accordance with the terms of the Muskrat Falls PPA.

The resulting impact of the increase to the working capital allowance related to Muskrat Falls supply costs on return on rate base is approximately \$6.2 million.⁵⁶

5.4 Return and Capital Structure

Return for Hydro is a function of the average rate base, discussed above, and the weighted average cost of capital.

⁵⁵ As there is no set schedule for rate mitigation funding, for the purpose of the calculation of working capital, Hydro has assumed that rate mitigation funding is received consistent with the timing of Hydro's Utility customer payments. This minimizes the impact of any timing difference between the receipt of rate mitigation funding and the timing of payment of corresponding supply costs, preventing a further increase in the working capital allowance.

⁵⁶ Working Capital Allowance – Muskrat Falls Related (\$115.1) x 2019 Test Year Rate of Return on Rate Base (5.43%) = \$6.2.

5.4.1 Weighted Average Cost of Capital

- Hydro's weighted average cost of capital for the 2027 Test Year is 4.88% compared to 5.43% in the 2019 Test Year, as provided in Table 5-9.⁵⁷

Table 5-9: Weighted Average Cost of Capital (%)⁵⁸

	2019 Test Year	2027 Test Year
Proportion of Capital Structure:		
Debt	76.80	74.50
Asset Retirement Obligation ⁵⁹	0.61	0.74
Employee Future Benefit ⁶⁰	3.12	3.01
Equity	19.48	21.76
Total Average Capital Structure	100.00	100.00
Embedded Cost of Debt	4.91	4.05
Return on Equity	8.50	8.60
Weighted Average Cost of Debt ⁶¹	3.77	3.02
Weighted Average Cost of Equity ⁶²	1.66	1.87
Weighted Average Cost of Capital	5.43	4.88

- The resulting impact on return on rate base of the reduction in weighted average cost of capital is approximately \$15.3 million⁶³ from the 2019 Test Year to the 2027 Test Year.

⁵⁷ Please refer to Schedule D-II, p. 3.

⁵⁸ The numbers may not add due to rounding.

⁵⁹ This item has zero cost in the capital structure.

⁶⁰ This item has zero cost in the capital structure.

⁶¹ Weighted Average Cost of Debt = Debt Proportion of Capital Structure x Embedded Cost of Debt.

⁶² Weighted Average Cost of Equity = Equity Proportion of Capital Structure x Return on Equity.

⁶³ Reduction in Weighted Average Cost of Capital (5.43% - 4.88%) x 2027 Test Year Average Rate Base (\$2,802.0). Numbers may not add due to rounding.

Cost of Debt

Table 5-10 provides Hydro's average debt, finance charges, and embedded cost of debt for the 2019 and 2027 Test Years.⁶⁴

Table 5-10: Embedded Cost of Debt (\$ Millions)

	2019 Test Year	2027 Test Year
Average Debt	1,835.1	2,562.6
Finance Charges ⁶⁵	90.2	103.6
Embedded Cost of Debt (%)	4.91	4.05

Hydro's increase in average debt from the 2019 Test Year to the 2027 Test Year is primarily driven by its capital additions; however, the average cost of debt is forecast to decline from the 2019 Test Year to the 2027 Test Year, causing a decrease in the embedded cost of debt. This reflects lower average coupon rates on more recent debt issuances and the retirement of debt with higher rates.

5.5 Return on Rate Base

Return on rate base is provided in Table 5-11.⁶⁶

Table 5-11: Return on Rate Base (\$ Millions)⁶⁷

	2019 Test Year	2027 Test Year
Average Rate Base⁶⁸	2,317.3	2,802.1
Regulated Returns		
Net Interest ⁶⁹	95.2	81.3
Net Income ⁷⁰	30.6	55.4
Return on Rate Base	125.8	136.7
Rate of Return on Rate Base (%)	5.43	4.88
Allowable Return on Rate Base Range (+/-0.20) (%)	5.23 to 5.63	4.68 to 5.08

⁶⁴ Please refer to Schedule D-IV.

⁶⁵ Please refer to Schedule D-IV.

⁶⁶ Please refer to Schedule D-II, p. 4.

⁶⁷ Numbers may not add due to rounding.

⁶⁸ Please refer to Table 5-7.

⁶⁹ Please refer to Schedule D-II, p. 4. Regulated Interest plus Interest Cost of Service Exclusions.

⁷⁰ Please refer to Schedule D-II, p. 4. Net Income plus Depreciation on Assets Excluded from Rate Base.

The increase in return on rate base of \$10.9 million from the 2019 Test Year to the 2027 Test Year is primarily due to an increase of \$26.2 million due to an increase in average rate base.⁷¹ This is partially offset by a reduction of \$15.3 million due to a decrease in the weighted average cost of capital.⁷²

5.6 Deferred Charges and Proposed Deferral Accounts

Deferred Charges represent expenses incurred by Hydro that are deferred and subsequently transferred, disposed of, or amortized and/or recovered over a defined period of time, as approved by the Board. Please refer to Schedule D-V for the 2027 Test Year summary of deferred charges. Hydro's proposals are further detailed below.

5.6.1 Business Systems Transformation Program Deferral Account Amortization

Board Order No. P.U. 27(2022) approved the recovery of actual and forecast deferred costs of \$6.7 million up to the end of 2022 associated with the Business Systems Transformation Program through customer rates, to be implemented in Hydro's next GRA.⁷³ Hydro requested approval of an additional \$7.8 million of forecast costs deferred up to December 31, 2026, relative to the Business Systems Transformation Program, in its Recovery of Costs Associated with Information Systems Assets Application,⁷⁴ currently before the Board, with disposition to be proposed in its GRA. The proposed amortization period reflects a balanced approach that moderates near-term rate impacts to customers while ensuring timely recovery of prudently incurred costs. Hydro is proposing the amortization and recovery of the forecast January 1, 2027 deferral account balance of \$14.5 million beginning in 2027 over an eight-year period. This timeframe is consistent with the typical cadence of GRAs, which are generally filed by regulated utilities every three to five years, such that the proposed amortization period spans approximately two regulatory review cycles. For purposes of the 2027 Test Year, Hydro has included \$1.8 million of amortization of the deferral account balance in its revenue requirement.

5.6.2 Allowance for Funds Used During Construction Deferral Account Amortization

On April 14, 2026, Hydro filed its application for approval of a deferral account to capture the difference between using interest during construction to calculate capitalized financing costs, as required by

⁷¹ Please refer to Section 5.3.1 and Section 5.3.2. (2027 Test Year Average Rate Base (\$2,802.1) - 2019 Test Year Average Rate Base (\$2,317.3)) x 2019 Test Year Weighted Average Cost of Capital (5.43%). Numbers may not add due to rounding.

⁷² Please refer to Section 5.4.1.

⁷³ In Hydro's application, deferred costs up to 2022 were estimated at \$6.7 million.

⁷⁴ "Recovery of Costs Associated with Information System Assets," Newfoundland and Labrador Hydro, March 31, 2026.

International Financial Reporting Standards, and Hydro's proposed methodology of allowance for funds used during construction.⁷⁵ The deferral account is proposed to be effective January 1, 2026 and included in rate base. In accordance with the proposed definition, pending approval by the Board, the account will be amortized based on the composite depreciation rate⁷⁶ in the latest depreciation study approved by the Board. Additions to the account are amortized beginning in the year following. The application is currently before the Board. The forecast balance in the account as of January 1, 2027 is \$2.1 million and, for purposes of the 2027 Test Year, Hydro has included \$0.1 million of amortization of the deferral account balance in its revenue requirement.

5.6.3 Frequency Converter Depreciation Deferral Account Disposition

Board Order No. P.U. 35(2020) approved the deferral of the cumulative revenue requirement impact associated with the loss on the sale of the frequency converter to Corner Brook Pulp and Paper Limited. The Board directed that the disposition of the cumulative revenue requirement impact included in the Frequency Converter Depreciation Deferral Account balance be addressed as part of Hydro's next GRA. The allocation of the balance to customers is based on the overall 2019 Test Year revenue requirement impact of the loss on disposal of the frequency converter. As noted in its application for the deferral account, Hydro calculated the impact for each customer by re-computing its 2019 Test Year Cost of Service Study, reflecting the removal of the loss on disposal of the frequency converter from the rates.⁷⁷ This calculation and the resulting allocation are presented in Table 5-12. The deferral account balance is currently a regulatory liability due to customers of \$1.6 million. Hydro is proposing that the deferral account balance of \$1.6 million be disposed of through disposition or transfer to the Supply Cost Variance Deferral Account for Island Interconnected System customers and through transfer to the respective Revenue Deficiency Deferral accounts for Labrador customers.

⁷⁵ "Approval of a Deferral Account for an Allowance for Funds Used During Construction," Newfoundland and Labrador Hydro, April 14, 2026. The deferral account in this application is proposed to be effective January 1, 2026; therefore, Hydro filed this application outside of this GRA.

⁷⁶ The current Board-approved composite depreciation rate is 2.28%. The composite depreciation rate in the latest Depreciation Methodology Study is 2.34%, based on a weighted average of composite rates found in Exhibit 8, p. 4-3. A discussion of the methodology is also included in Exhibit 8, p. 4-3.

⁷⁷ "Application for Approval of an Account to Defer the Revenue Requirement Impact Associated with the Loss on the Sale of the Corner Brook Pulp and Paper Frequency Converter," Newfoundland and Labrador Hydro, November 12, 2020, sch. 1, p. 1, Table 2.

Table 5-12: Frequency Converter Depreciation Deferral Account Disposition⁷⁸

Customer Group	Change in Revenue Requirement (\$)	Allocation (%)	Total Amount Owing (\$)	Proposed Disposition
Newfoundland Power	197,898	86.4	(1,397,756)	Transfer to Supply Cost Variance Deferral Account - "Utility Customer Balance."
Rural Isolated	190	0.1	(1,342)	Transfer to Supply Cost Variance Deferral Account - "Utility Customer Balance."
Island Industrial	13,439	5.9	(94,920)	Transfer to Supply Cost Variance Deferral Account - "Industrial Customer Balance."
Rural Labrador	13,863	6.0	(97,915)	Transfer to Rural Labrador Revenue Deficiency Account.
Labrador Industrial	3,738	1.6	(26,402)	Transfer to Labrador Industrial Revenue Deficiency Account.
	229,128	100	(1,618,334)	

5.6.4 Phase Two Hearing Costs Deferral Account Amortization

Board Order No. P.U. 13(2016) directed Hydro to create a separate account for inclusion of professional services-consulting fees, salary transfers and overtime costs for 2014, 2015 and subsequent years relating to Phase Two of the Board's investigation into the January 2014 outages, with disposition subject to a future application. In December 2019, the Board concluded the Phase Two proceeding.⁷⁹ The proposed amortization period reflects a balanced approach that moderates near-term rate impacts to customers while ensuring timely recovery of prudently incurred costs. Hydro is proposing the amortization and recovery of the deferral account balance as at January 1, 2027 of \$1.7 million over a period of eight years, commencing in 2027. This timeframe is consistent with the typical cadence of general rate applications, which are generally filed by regulated utilities every three to five years, such

⁷⁸ Numbers may not add due to rounding.

⁷⁹ In its correspondence, the Board stated: "Phase Two of the Board's Investigation into Supply Issues and Power Outages on the Island Interconnected System will be concluded and that any concerns in relation to adequacy and reliability of supply on the Island Interconnected system upon interconnection with the Muskrat Falls Project will be addressed in the Board's review of the Reliability and Resource Adequacy Study filed by Hydro on November 16, 2018." Please refer to "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Phase Two - Conclusion / Review of the Reliability and Resource Adequacy Study - Record and Proceeding," Board of Commissioners of Public Utilities, December 4, 2019.

that the proposed amortization period spans approximately two regulatory review cycles. For purposes of the 2027 Test Year, Hydro has included \$0.2 million of amortization of the deferral account balance in its revenue requirement.

5.6.5 Reliability and Resource Adequacy Study Review Deferral Account Amortization

Board Order No. P.U. 29(2019) approved the deferral account for the Board’s external consulting costs and approved intervenor costs associated with the *Reliability and Resource Adequacy Study Review*. The order stated that Hydro shall apply for recovery of costs charged to the deferral account through its next GRA. In 2021, the account definition was expanded in Board Order No. P.U. 8(2021) to include Hydro’s external costs for professional services and contractors related to the “Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station.”⁸⁰ The forecast balance in the account for December 31, 2027, prior to amortization, is \$5.1 million. The proposed amortization period reflects a balanced approach that moderates near-term rate impacts to customers while ensuring timely recovery of prudently incurred costs. Hydro is proposing the amortization and recovery of the forecast December 31, 2027 deferral account balance over a period of eight years, commencing in 2027. This timeframe is consistent with the typical cadence of GRAs, which are generally filed by regulated utilities every three to five years, such that the proposed amortization period spans approximately two regulatory review cycles. For purposes of the 2027 Test Year, Hydro has included \$0.6 million of amortization of the deferral account balance in its revenue requirement.

5.6.6 Muskrat Falls PPA Sustaining Capital Deferral Account Amortization

Board Order No. P.U. 33(2021) approved Hydro’s Muskrat Falls PPA Sustaining Capital Deferral Account effective on the date upon which Hydro was required to begin payments under the Muskrat Falls PPA.⁸¹ The Board noted in its Order that a decision on how the payments would be recovered from customers was to be determined in Hydro’s next GRA. Further information on Muskrat Falls Sustaining Capital and the deferral account is provided in Chapter 4, Section 4.3.2. Additions to the account began to be amortized in the year following, and the forecasted deferral account balance as at January 1, 2027 is \$43.6 million. Hydro is proposing that the amortization of the deferral be based on the composite

⁸⁰ “Newfoundland and Labrador Hydro HTGS Condition Assessment and Life Extension Study – Project Report Volume 1,” Hatch Ltd., March 30, 2022. Provided in “*Reliability and Resource Adequacy Study Review – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station*,” Newfoundland and Labrador Hydro, March 31, 2022, att. 2.

⁸¹ The Muskrat Falls Hydroelectric Generating Facility was commissioned in November 2021, upon which Hydro was required to begin making payments under the Muskrat Falls PPA.

depreciation rate of the Muskrat Falls Hydroelectric Generating Facility and Labrador Transmission Assets of 1.42% and 1.71%, respectively, as recommended by Concentric in their memo included in Exhibit 9. For purposes of the 2027 Test Year, Hydro has included \$0.7 million of amortization of the deferral account balance in its revenue requirement. A revised deferral account definition, with updated proposed disposition, is included in Exhibit 10.

5.6.7 Electrification Cost Deferral Account Amortization

Board Order No. P.U. 33(2023) approved Hydro's Electrification Cost Deferral Account definition, with an effective date of January 1, 2023, and stated that disposition of the balance in this account will be subject to a further Order of the Board. The forecast balance in the account for December 31, 2026, prior to amortization, is \$1.0 million. Hydro is proposing that the deferral account balance be recovered through a rate rider over ten years, at \$0.1 million per year, to be consistent with the method and period of recovery of the CDM Cost Deferral balance for the Island Interconnected System. The rate rider is proposed to commence on July 1, 2027, and therefore includes six months of recovery or \$54,000. A revised deferral account definition, with updated proposed disposition, is included in Exhibit 10.

5.6.8 Return on Equity Rate Change Deferral Account Amortization

As per Board Order No. P.U. 49(2016), Hydro's target return on equity percentage must be adjusted as required to equal the return on equity approved for Newfoundland Power.⁸² Newfoundland Power's return on equity of 8.60% effective January 1, 2025, was approved in Board Order No. P.U. 3(2025). Hydro's updated return on equity, also effective January 1, 2025, was approved in Board Order No. P.U. 10(2025).

Further, Board Order No. P.U. 10(2025) approved Hydro's proposed modifications to the Return on Equity Rate Change Deferral Account definition to allow for balances attributable to Newfoundland Power and Island Industrial Customers to be transferred to the Supply Cost Variance Deferral Account on March 31 of each year. The Board also accepted Hydro's proposal that any balances related to Labrador Industrial and Hydro Rural Labrador Interconnected customers would be proposed for disposition at Hydro's next GRA. Hydro is proposing that the forecast deferral account balance as of

⁸² OC2009-063 directed the Board to set the same target return on equity to be used in the calculation of the return on rate base for all future GRAs filed by Hydro as was most recently set for Newfoundland Power.

January 1, 2027, related to Labrador Industrial customers (\$11,288) and Hydro Rural Labrador Interconnected Customers (\$44,572) be transferred to the respective Revenue Deficiency deferral accounts to be recovered in customer rates, as further outlined in Chapter 6.

5.6.9 GRA Hearing Cost Deferral Account Amortization

Hydro is forecast to incur approximately \$1.5 million in external regulatory costs with respect to the current application. Hydro is proposing to defer and amortize these costs over four years commencing in 2027, consistent with past regulatory practice of the Board.⁸³ This timeframe is consistent with the typical cadence of GRAs, which are generally filed by regulated utilities every three to five years. For purposes of the 2027 Test Year, Hydro has included \$0.4 million of amortization of the deferral account balance in its revenue requirement.

5.6.10 Holyrood TGS Accelerated Depreciation Deferral Account

In Board Order No. P.U. 33(2021), the Board approved the establishment of a Holyrood TGS Accelerated Depreciation Deferral Account to defer differences in excess of \$2.5 million between the test year depreciation expense and the actual accelerated depreciation for the Holyrood TGS assets in 2022 and 2023, assuming these years were not test years.

On November 30, 2023, Hydro filed an application for approval to extend the operation of the Holyrood TGS Accelerated Depreciation Deferral Account to continue to defer the difference between the actual accelerated depreciation expense for the Holyrood TGS and the approved test year costs until the end-of-steam generation. In Board Order No. P.U. 1(2024), the Board approved Hydro's application and directed Hydro to file a report on the activity and operation of the Holyrood TGS Accelerated Depreciation Deferral Account with its next GRA. Hydro has attached the memo as Exhibit 11. Hydro is not proposing the disposition of the balance in the account at this time for the reasons outlined in its memo.

⁸³ The Board has allowed recovery of application costs over a three-year period, with the most recent approval for Hydro outlined in Board Order No. P.U. 16(2019). The Board approved the amortization of Newfoundland Power's 2025-2026 GRA hearing costs over a 30-month period in Board Order No. P.U. 3(2025). As noted in Chapter 6, Hydro is proposing its next rate-setting year to be 2031, which will reflect any changes to Government's rate mitigation plan, currently in place up to and including 2030.

5.7 Proposal of Long-Term Supply Cost Variance Deferral Account

5.7.1 Background

Hydro's Supply Cost Variance Deferral Account was approved effective November 1, 2021.⁸⁴ The Supply Cost Variance Deferral Account enables the deferral of costs related to Hydro's requirement to commence payment of Muskrat Falls Project costs⁸⁵ prior to recovering these costs.⁸⁶ In the application requesting approval of the Supply Cost Variance Deferral Account, Hydro indicated it would provide evidence on a long-term approach to the Supply Cost Variance Deferral Account in its next GRA, including a proposed allocation and recovery approach for any account balance.

Hydro submitted an application on April 16, 2025, for approval of the creation of a new Long-Term Supply Cost Variance Deferral Account.⁸⁷ Subsequent to the application, Hydro filed an application for review and approval of the updated Cost of Service Methodology, the outcome of which could potentially impact Hydro's proposals for the Long-Term Supply Cost Variance Deferral Account. As a result, on May 23, 2025, Hydro requested that the Long-Term Supply Cost Variance Deferral Account be paused until the conclusion of the Cost of Service Methodology proceeding.⁸⁸

The existing Supply Cost Variance Deferral Account accumulates costs, revenues and variances from the 2019 Test Year until the conclusion of Hydro's 2026 GRA; after that time, once a new test year is approved, Hydro proposes transitioning to the Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027. Hydro will propose the disposition of any balances remaining in the existing

⁸⁴ Board Order Nos. P.U. 33(2021) and P.U. 4(2022).

⁸⁵ Muskrat Falls Project costs are comprised of payments made under: (i) the Muskrat Falls PPA and (ii) the Transmission Funding Agreement. 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.

⁸⁶ The Supply Cost Variance Deferral Account also includes variances for costs and revenues from Hydro's approved test year for items such as fuel costs associated with the 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 Supply Cost Variance Deferral Account definition reflects the calculation of financing charges based on Hydro's short-term borrowing costs.

⁸⁷ The application also contained proposed cost of service allocation methodologies for certain components of the Supply Cost Variance Deferral Account that had not previously been addressed, as well as an accounting deviation necessary as a result of the amalgamation of the former Nalcor and Hydro.

⁸⁸ The regulatory proceeding of Hydro's Cost of Service Methodology Application is ongoing.

Supply Cost Variance Deferral Account after the transition to the Long-Term Supply Cost Variance Deferral Account in an application following the GRA.⁸⁹

5.7.2 Allocation Methodology

Hydro's proposed long-term approach is the creation of a new deferral account called the Long-Term Supply Cost Variance Deferral Account, which is separate from the existing Supply Cost Variance Deferral Account, with components consistent with the current Supply Cost Variance Deferral Account, but includes corresponding allocation methodologies between customer classes. Hydro reviewed the definition of the existing Supply Cost Variance Deferral Account for changes to be proposed to the deferral account definition for the Long-Term Supply Cost Variance Deferral Account, including the methodology for allocating variances to the plan balances for Newfoundland Power and the Island Industrial customers. As part of this review, Hydro engaged CA Energy to review the deferral account practices in other jurisdictions that may provide alternative methods to be considered by Hydro in the long term.

CA Energy prepared a report, "Costing and Pricing for Deferral Accounts," which is included as Exhibit 12. 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 in Exhibit 13, assuming an illustrative test year with Muskrat Falls supply costs and rate mitigation reflected in rates. The allocation of variances in the example of approximately \$45.8 million resulted in shifting \$0.8 million in costs to Newfoundland Power from Island Industrial customers using both demand and energy allocators when compared to an energy-only allocator. This shift in costs using

⁸⁹ In its 2021 Supply Cost Accounting Application to establish the existing SCVDA, Hydro proposed to file a future application with the Board, subsequent to the next GRA Order, to deal with allocation and recovery of the balance in the Supply Cost Variance Deferral Account that accumulates prior to the conclusion of the next GRA. Please refer to "Supply Cost Accounting Application," Newfoundland and Labrador Hydro, July 29, 2021, sch. 1, p. 3/10–13.

- 1 allocators consistent with those used in the cost of service resulted in an estimated difference in billing
2 impact to Newfoundland Power of a 0.1% increase and Island Industrial Customers of a -2.3% decrease.
- 3 Hydro recognizes that using the allocators in the cost of service to allocate variances from those costs in
4 the Long-Term Supply Cost Variance Deferral Account would result in a more accurate allocation of costs
5 between customers. Hydro proposes using the allocators approved for the test year's cost of service to
6 classify costs and credits as demand or energy-related.
- 7 Table 5-13 lists the Supply Cost Variance Deferral Account components and the proposed allocators, all
8 of which are consistent with the cost of service allocations already approved for use or proposed for
9 approval in Hydro's Cost of Service Methodology Application or this GRA.

**Table 5-13: Demand and Energy Classification – Supply Cost Variance Deferral Account
Long-Term Components**

Component	Demand (%)	Energy (%)	Cost of Service Allocation⁹⁰	Approved Board Order No.
Muskrat Falls Project Costs	50	50	System Load Factor	P.U. 37(2019)
Net Revenue from Exports	50	50	System Load Factor	P.U. 37(2019)
Transmission Tariff Revenue	50	50	System Load Factor	Proposed – Cost of Service Methodology Application
Rate Mitigation Funding	50	50	System Load Factor	Proposed – Cost of Service Methodology Application
Holyrood TGS Fuel	0	100	Energy	P.U. 30(2019)
Utility Load	50	50	System Load Factor	Proposed – Cost of Service Methodology Application
Industrial Load	50	50	System Load Factor	Proposed – Cost of Service Methodology Application
Greenhouse Gas Credits Revenue	50	50	System Load Factor	Proposed – Cost of Service Methodology Application
Other IIS Supply Cost				
Thermal	100	0	Demand	P.U. 37(2019)
Off-Island Purchases	50	50	System Load Factor	P.U. 37(2019)
On-Island Purchases	50	50	System Load Factor	P.U. 37(2019)
Wind Purchases	43	57	Demand/Energy	Proposed - GRA

⁹⁰ 2027 Test Year System Load Factor is 50%; therefore, 50% demand and 50% energy were used by Hydro in this application for illustrative purposes.

To allocate the demand and energy costs to the Island Interconnected customer groups, Hydro is proposing the methodology outlined below.

5.7.3 Energy Allocation

Each month, the energy costs will be allocated among the Island Interconnected customer groups of: (i) Newfoundland Power; (ii) Island Industrial Firm; and (iii) 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.

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, in between test years, written off to Hydro's net income (loss) consistent with past practice.

5.7.4 Demand Allocation

Each month, the demand costs will be allocated among the Island Interconnected System customer groups of: (i) Newfoundland Power; (ii) Island Industrial Firm; and (iii) 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, in between test years, written off to Hydro's net income (loss) consistent with past practice.

5.7.5 Load Variation

The load variation in the Supply Cost Variance Deferral Account removes revenue variations from test year sales to Newfoundland Power and Hydro's Island Industrial Customers. 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 Supply Cost Variance Deferral Account 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 energy⁹¹ for Newfoundland Power and the average embedded cost of energy for Island Industrial Customers based on the 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 on 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 Supply Cost Variance Deferral Account.

Therefore, Hydro proposes to allocate the load variation in the Long-Term Supply Cost Variance Deferral Account 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).

5.7.6 Financing Charges

During the proceeding related to Hydro's application establishing the existing Supply Cost Variance Deferral Account, parties raised concerns in relation to the proposed calculation of finance charges on

⁹¹ 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 Supply Cost Variance Deferral Account. In its application, Hydro had proposed to calculate financing charges using the approved weighted average cost of capital, given the proposed blending of historical balances from existing deferral accounts with the payments under the Muskrat Falls PPA. The Island Industrial Customer 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 weighted average cost of capital 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 that the calculation of finance charges on the existing Supply Cost Variance Deferral Account 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 can continue to be calculated using Hydro's approved weighted average cost of capital, 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 Supply Cost Variance Deferral Account.

Since the establishment of the existing Supply Cost Variance Deferral Account, Hydro has implemented a Project Cost Recovery Rider⁹² 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 Supply Cost Variance Deferral Account 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, where cost variances are collected annually. In the case of the existing Supply Cost Variance Deferral Account, collections of balances come from two sources: customers and rate mitigation funding.

Hydro's proposal is for the Long-Term Supply Cost Variance Deferral Account to come into effect on January 1, 2027. This account will continue to capture variances between Hydro's incurred supply costs

⁹² A Project Cost Recovery Rider was implemented for Newfoundland Power on July 1, 2022, and for Island Industrial Customers on January 1, 2024.

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 Supply Cost Variance Deferral Account as project costs and rate mitigation funding will be included in Hydro's cost of service and test year revenues, prior to this account becoming effective. Contrary to the existing Supply Cost Variance Deferral Account, 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 Rate Stabilization Plan, where balances in the account are collected annually. For these reasons, this long-term approach to the Supply Cost Variance Deferral Account differs from the existing Supply Cost Variance Deferral Account at the time it was established; Hydro is proposing that the interest on the Long-Term Supply Cost Variance Deferral Account be calculated according to current regulatory practice in Newfoundland and Labrador, using the weighted average cost of capital as approved in Hydro's test year. The calculation of finance charges based on Hydro's approved weighted average cost of capital has been included in the proposed account definition.

5.7.7 Summary

The Supply Cost Variance Deferral Account 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 GRA; after which, Hydro will transition to the Long-Term Supply Cost Variance Deferral Account.

Hydro is proposing its Long-Term Supply Cost Variance Deferral Account be effective January 1, 2027, with the proposed account definition included in Exhibit 10. The proposals described herein for the Long-Term Supply Cost Variance Deferral Account definition include the allocation methodology, which is proposed to be consistent with the latest Cost of Service Study approved by the Board. In addition, proposals have been described 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.

5.8 Hydro's Proposals

Hydro is requesting the Board approve the following proposals:

- For the purposes of calculating Hydro's 2027 Test Year:
 - A 2027 Test Year revenue requirement of \$797,713,000;
 - A 2027 forecast average rate base of \$2,802,095,000;
 - A rate of return on rate base of 4.88% in a range of 4.68% to 5.08%;
 - Hydro's forecast capital structure for 2027, with a weighted average cost of capital of 4.88%;
and
 - The Holyrood conversion rate of 563 kWh per barrel.
- Hydro's continued use of the working capital allowance methodology, as set out in Chapter 5 of the evidence in support of this application, and the separation of Muskrat Falls supply costs and related transactions to be allocated to the Island Interconnected System.
- Hydro's proposed depreciation rates and methodology, as set out in Chapter 5 and Exhibits 7 and 8 of the evidence.
- The disposition and amortization of balances in existing regulatory deferral accounts, as set out in Section 5.6. More particularly:
 - The amortization and recovery of the Business Systems Transformation Program Deferral Account balance of \$14.5 million, over a period of eight years, commencing January 1, 2027, at a rate of \$1.8 million per year;
 - The Frequency Converter Depreciation Deferral Account balance of \$1.6 million due from customers be disposed of through disposition or transfer to the Supply Cost Variance Deferral Account for Island Interconnected System customers and through transfer to the respective Revenue Deficiency deferral accounts for Labrador customers;
 - The amortization and recovery of the Phase Two Hearing Costs Deferral Account balance as at January 1, 2027 of \$1.7 million over a period of eight years, commencing in 2027, at \$0.2 million per year;

- The amortization and recovery of the *Reliability and Resource Adequacy Study Review* forecast December 31, 2027 deferral account balance, prior to amortization, of \$5.1 million over a period of eight years, commencing in 2027 at \$0.6 million per year;
- The amortization of the Muskrat Falls PPA Sustaining Capital Deferral Account be based on the composite depreciation rate of the Muskrat Falls Hydroelectric Generating Facility and Labrador Transmission Assets of 1.42% and 1.71%, respectively, as recommended by Concentric, in accordance with the revised deferral account definition in Exhibit 10;
- The recovery of the Electrification Cost Deferral Account balance forecast at December 31, 2026, in accordance with the proposed definition included in Exhibit 10, which is consistent with the recovery of the CDM Cost Deferral Account. Amortization of \$0.1 million to be recovered in the 2027 Test Year through a rate rider;
- The forecast Return on Equity Rate Change Deferral Account balance as of January 1, 2027 related to Labrador Industrial customers (\$11,288) and Hydro Rural Labrador Interconnected customers (\$44,572) be transferred to the respective Revenue Deficiency deferral accounts to be recovered in customer rates; and
- Deferral and recovery of external GRA hearing costs, estimated to be \$1.5 million, with amortization of these costs occurring over four years commencing in 2027.
- The creation of a new Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027, with allocations among customer classes based on the latest Cost of Service Study approved by the Board and interest calculated based on the weighted average cost of capital in Hydro's latest approved test year.

Chapter 6

Rates and Regulations



Chapter 6: Rates and Regulations

6.1 Overview

On the Island Interconnected System, Hydro provides electricity service to Newfoundland Power and six Industrial customers: (i) Linde; (ii) Braya; (iii) CBPP; (iv) Marathon; (v) Teck; and (vi) Vale. Hydro also serves approximately 23,400 Rural customers at the retail level on the Island Interconnected System.

On the Labrador Interconnected System, Hydro serves approximately 11,700 Rural customers and two Industrial customers.¹ On the Isolated systems, including the L’Anse-au-Loup system, Hydro has approximately 4,500 customers.

To determine fair rates for its customers, Hydro prepares Cost of Service studies for five systems:

- 1) Island Interconnected;
- 2) Island Isolated;
- 3) Labrador Isolated;
- 4) L’Anse-au-Loup; and
- 5) Labrador Interconnected.

The rates are grouped into the following classifications:

- Island Interconnected Utility (Newfoundland Power);
- Island Interconnected Industrial Customers;
- Island Interconnected and L’Anse-au-Loup Rural Customers;
- Island and Labrador Isolated Rural Customers – Non-Government;
- Island and Labrador Isolated Rural Customers – Government;
- Labrador Interconnected Rural Customers; and
- Labrador Industrial Customers.

¹ Under the *EPCA*, the rate charged to Labrador Industrial customers on the Labrador Interconnected System for transmission-related costs is regulated, and generation supply to customers is non-regulated.

6.2 2018 Cost of Service Methodology Review

Hydro's 2018 Cost of Service Methodology Review Application was filed with the Board on November 15, 2018, pursuant to a Settlement Agreement filed in Hydro's 2017 GRA. The application proposed revisions to Hydro's Cost of Service Methodology for use in the determination of test year class revenue requirements, reflecting the inclusion of the Muskrat Falls supply costs upon full commissioning.

In accordance with the established schedule for the proceeding, the parties engaged in settlement discussions during September 2019, which were facilitated by Board Hearing Counsel. On October 4, 2019, a Settlement Agreement was filed with the Board ("2019 Settlement Agreement") setting out the agreement of the parties to the application on all issues arising from the application. The 2019 Settlement Agreement stated:

The Parties agree that the Cost of Service Methodology approved by the Board in this Cost of Service Methodology Application shall be the accepted methodology for use in the first General Rate Application filed to address recovery of Muskrat Falls Project costs upon full commissioning, except for any particular issues identified in this Settlement Agreement for further review in the GRA, after which a Cost of Service Methodology Review may be conducted upon request of any of the Parties and approval by the Board for such review.²

As part of the 2019 Settlement Agreement, the parties agreed to certain proposals regarding the Cost of Service. These proposals and the 2019 Settlement Agreement were approved in Board Order No. P.U. 37(2019) and the various agreed-upon items have been implemented in Hydro's calculation of the Cost of Service provided within this application. The implemented items are as follows:

- 1)** The functionalization of power purchase costs resulting from the Muskrat Falls PPA and the Transmission Funding Agreement as generation;
- 2)** The functionalization of Hydro's existing generation and transmission assets have remained the same, with the exception of:
 - a.** The functionalization of Transmission Lines TL234 and TL263 as transmission; and

² "2019 Settlement Agreement," October 4, 2019, p. 2, para. 7.

- 1 **b.** The functionalization of the Holyrood TGS Unit 3 as transmission after the unit is
2 permanently converted into the role of synchronous condenser;³
- 3 **3)** The functionalization of net export revenues as generation, in the same manner as the
4 functionalization of the Muskrat Falls Project costs;
- 5 **4)** The classification between demand and energy for the power purchase costs resulting from the
6 Muskrat Falls PPA and the Transmission Funding Agreement is based on system load factor. This
7 is inclusive of the costs related to the Muskrat Falls generation, the LIL, and the Labrador
8 Transmission Assets;
- 9 **5)** Net export revenues are classified using the system load factor, in the same manner as the
10 classification of the Muskrat Falls Project costs; and
- 11 **6)** Net export revenues are included in the cost of service to reduce the supply costs related to the
12 Muskrat Falls Project (inclusive of Muskrat Falls generation, the LIL and the Labrador
13 Transmission Assets) to be recovered through the rates of customers on the Island
14 Interconnected System.

15 Board Order No. P.U. 37(2019) also set out the following to be filed by Hydro as part of its next GRA:

- 16 **1)** A report with recommendations of a review by Hydro to: (i) identify any projects and spending
17 in its CDM plan that are justified in whole or in part based on demand-related savings; (ii) assess
18 how demand-related CDM is classified in other jurisdictions; and (iii) provide options regarding
19 establishing a materiality threshold to assess if a change in approach is appropriate;
- 20 **2)** A report of a review by Hydro of the contribution of different customer classes to the
21 uncertainty parameters in its planning studies (e.g., P50 vs P90), to ensure the calculation of
22 peaks used in the Cost of Service Study appropriately reflects the contribution of the different
23 customer classes to the coincident peak used for planning purposes;
- 24 **3)** Details of the results of Hydro's cost tracking for specifically assigned assets and its assessment
25 of the feasibility of using actual expenses in the calculation of specifically assigned charges;

³ As per "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, the Holyrood TGS shall remain available for a "Bridging Period" until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

- 1 **4)** A report of a review by Hydro of the methodology for the calculation of the MW credit provided
2 to Newfoundland Power to ensure reasonableness; and
- 3 **5)** A proposal for the specific deferral mechanism to account for variations from forecast net
4 export revenues in the test year Cost of Service Study.⁴

6.2.1 2025 Cost of Service Methodology Application

6 Hydro filed its 2025 Cost of Service Methodology Application on August 22, 2025. The application
7 addressed the reports and proposals required to be filed pursuant to Board Order No. P.U. 37(2019).
8 The application also addressed Cost of Service Methodology issues currently identified as needing
9 direction or approval to incorporate in the Cost of Service to be filed in Hydro's 2026 GRA.

10 In the 2025 Cost of Service Methodology Application, Hydro requested the Board approve the following:

- 11 **1)** CDM program costs for the Labrador Interconnected System, including re-allocated amounts, be
12 functionalized as generation;
- 13 **2)** The classification between demand and energy for the CDM program costs in Labrador be based
14 on system load factor;
- 15 **3)** The portion of the CDM program costs in Labrador classified as energy be added to the
16 production demand costs for recovery in the generation demand rate charged to the Labrador
17 Industrial customers;
- 18 **4)** Cost allocation for specifically assigned assets to utilize actual operating and maintenance costs,
19 comprised of a Direct Operating and Maintenance Charge calculated as the six-year average of
20 actual operating and maintenance expenses recorded against each specifically assigned asset, or
21 estimated costs where historical costs are not available, and an Indirect Operating and
22 Maintenance Charge calculated as the ratio of total indirect transmission operating and
23 maintenance to total direct transmission operating and maintenance, derived from the Cost of
24 Service Study;

⁴ On July 29, 2021, Hydro filed an application proposing the creation of a new Supply Cost Variance Deferral Account that was approved by the Board effective November 1, 2021, in Board Order Nos. P.U. 33(2021) and P.U. 4(2022). The Supply Cost Variance Deferral Account enables the deferral of variances for certain components of costs and revenues from Hydro's approved test year, including Hydro's net revenues from exports. The components of this deferral account, including variations from forecast net export revenues in the test year Cost of Service Study, are proposed to continue in Hydro's Long-Term Supply Cost Variance Deferral Account, as outlined in Chapter 5, Section 5.7.

- 1 **5)** The implementation of a 64 MW Hydraulic Credit for Newfoundland Power, with the process for
2 determination of the thermal generation credit to remain unchanged;
- 3 **6)** Rate mitigation funding be functionalized as generation;
- 4 **7)** The classification between demand and energy for rate mitigation funding shall be based on the
5 system load factor;
- 6 **8)** Transmission tariff revenue be functionalized as generation;
- 7 **9)** The classification between demand and energy for transmission tariff revenue shall be based on
8 the system load factor;
- 9 **10)** Greenhouse gas credit revenue be functionalized as generation; and
- 10 **11)** The classification between demand and energy for greenhouse gas credit revenue shall be based
11 on the system load factor.

12 A technical conference was held in October 2025, subsequent to which the parties engaged in
13 settlement discussions, facilitated by the Board’s Regulatory Consultant.

14 Hydro has predicated the Cost of Service Study included in this GRA on the principles and assumptions
15 approved in Board Order No. P.U. 37(2019), and on an agreement reached with the intervenors to the
16 2025 Cost of Service Methodology Application regarding the majority of proposals made by Hydro in
17 that application.⁵ The parties agreed to defer select issues to the 2026 GRA. These are proposals with
18 respect to the classification of the Holyrood TGS generation costs and fuel costs, and the
19 implementation of a 64 MW Hydraulic Credit for Newfoundland Power, with the process for the
20 determination of the thermal generation credit to remain unchanged. Hydro’s proposals for these
21 issues, as previously provided within the 2025 Cost of Service Methodology Application, are provided in
22 the following sections.

⁵ Hydro will file a fully executed copy of the Settlement Agreement reached in the 2025 Cost of Service Methodology Application for the record of this proceeding.

6.2.2 Holyrood TGS Costs – Allocation Methodology

In Board Order No. P.U. 37(2019), the Board accepted the following treatment for the Holyrood TGS:

- 1)** The Holyrood TGS Unit 3 shall be functionalized as a transmission after the unit is permanently converted into the role of a synchronous condenser;
- 2)** The classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor; and
- 3)** The fuel costs related to Holyrood are currently classified as energy, approved by the Board in Order No. P.U. 30(2019).

The Holyrood TGS continues to be operated primarily as a base load plant, as it was at the time of the previous settlement and Board Order regarding this issue. It has two units operating throughout the peak winter months, with the third unit brought on in anticipation of extremely cold weather and associated high levels of demand, then subsequently shut down with the return to normal winter conditions. If units at the Holyrood TGS are required to be online, Hydro utilizes energy from the LIL to keep the units operating at a minimum to reduce fuel consumption.

In the Reliability and Resource Adequacy Study – 2022 Update, Hydro reviewed the Holyrood TGS as a standby option. Hydro stated the following as part of the assessment:

To ensure sufficient generation is available on-Island in the event of an extended bipole LIL outage, on-Island generation must operate reliably. Standby generation must be dispatchable and able to synchronize with the grid quickly, ideally with a recall time within 10 minutes. The Holyrood TGS, as designed, is not ideally configured to meet these requirements. It was originally designed to be base loaded (i.e., limited starts, limited cycling), with a unit recall in excess of 24 hours.⁶

In addition to reducing recall time, Hydro must also improve the reliability of the units during startup. With a typical startup success rate of only approximately 50% and an average restoration time of three days following an unsuccessful start, the average time required to successfully recall a unit ranges from approximately two to three days. Therefore, Hydro does not consider the Holyrood TGS suitable for operation as a standby generating facility to be called upon in the event of an unplanned LIL outage, as it

⁶ “Reliability and Resource Adequacy Study – 2022 Update,” Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.3.1, p. 24/9–13.

is anticipated that even under the fastest recall scenario analyzed, there is a high probability of issues during startup, delaying synchronization of the units by several days.

Based on the current operation of the Holyrood TGS, which is largely unchanged from its operation when Board Order No. P.U. 37(2019) was issued, Hydro engaged CA Energy to provide an opinion on the current cost of service treatment for Holyrood TGS costs, including fuel. The memorandum prepared by CA Energy, titled “Treatment of Holyrood Generating Station Costs,” is included as Exhibit 14. CA Energy notes that:

In the past, Holyrood fuel was classified as energy-related, a position supported not only by industry practice but matching the role of Holyrood as a base load generator. In the medium term, the continuation of two of Holyrood’s units as base load, and industry practice regarding the treatment of fuel, suggest that this classification should continue.⁷

Based on the current operation of the Holyrood TGS, which is anticipated to continue through the Bridging Period, combined with the opinion of CA Energy, Hydro proposes that the cost of service treatment remain the same for the 2027 Test Year, with the allocation of costs reviewed for each subsequent GRA. Hydro further recommends the continuation of the following cost of service treatment of Holyrood TGS:

- 1) The classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor; and
- 2) Holyrood TGS fuel costs be classified as 100% energy.

6.2.3 Generation Credit Provided to Newfoundland Power

The 2019 Settlement Agreement required a report on a review by Hydro of the methodology for the calculation of the MW credit provided to Newfoundland Power to ensure reasonableness. Hydro’s assessment and report titled “Newfoundland Power Generation During Island Interconnected System Peaks” is provided as Exhibit 15.

In Hydro’s 2019 Test Year, Newfoundland Power’s generation credit was calculated based on the Island Interconnected System’s reserve at criteria. The existing calculation takes the total capacity of

⁷ “Treatment of Holyrood Generating Station Costs,” Christensen Associates Energy Consulting, July 30, 2025, p. 2. Provided as Exhibit 14.

Newfoundland Power generation and subtracts a reserve at criteria to arrive at a generation credit. Reserve at criteria is not the same as system reserve; to calculate the reserve at criteria, 240 MW of reserve margin was subtracted from the total Island Interconnected System capacity at peak, inclusive of capacity assistance contracts, to determine the maximum Island Interconnected System demand that can be supported on peak. The maximum demand that can be supported on peak is then used to calculate the percent reserve at criteria. The Newfoundland Power generation credit for the 2019 Test Year was 118.1 MW; the calculation is shown in Table 6-1.

Table 6-1: 2019 Test Year Newfoundland Power Generation Credit

	Capacity (MW)	Reserve at Criteria	Generation Credit (MW)
Hydraulic	94.2	1.128225	83.5
Thermal	39.0	1.128225	34.6
Total	133.2		118.1

To determine if the current methodology for the calculation of the generation credit to Newfoundland Power is reasonable, Hydro performed an analysis of historical data from January 2020 to December 2024 to determine the amount of hydraulic generation that Newfoundland Power was able to provide during times of high or peak load on the Island Interconnected System following a request from Hydro to maximize hydraulic generation. The study approach and results are contained in the report provided as Exhibit 15.

Based on the results of the analysis, Hydro believes that historical generation during Island system peaks is a more accurate reflection of the available generation from Newfoundland Power than the existing calculation. Hydro proposes a Hydraulic Credit of 64 MW for Newfoundland Power, which is the five-year historical average, 2020 to 2024, of Newfoundland Power's hydraulic generation at the time of system peak.

Newfoundland Power's thermal generation remains available to be called upon; however, there is a limited data set available to conduct an analysis similar to that conducted for the hydraulic credit. Therefore, Hydro recommends that the process for determining the thermal generation credit remain unchanged, determined by Newfoundland Power's thermal generation capability forecast for the test

1 year, reduced by the reserve at criteria. The proposed Newfoundland Power generation credit for the
 2 2027 Test Year is shown in Table 6-2.

Table 6-2: Newfoundland Power Generation Credit (MW)

	2027 Test Year
Thermal Capacity	44.5
Reserve at Criteria	1.132350
Thermal Generation Credit	39.3
Hydraulic Generation Credit	64.0
Total Newfoundland Power Generation Credit	103.3

3 **6.3 Cost of Service Methodology Review – New Proposal**

4 **6.3.1 Classification of Purchases of Wind Generation**

5 As described in Exhibit 4, Hydro purchases wind generation from wind farms in St. Lawrence and
 6 Fermeuse at a total of 54 MW of installed capacity.⁸ The 2019 Settlement Agreement for Hydro’s 2018
 7 Cost of Service Methodology Review provided for the purchase cost of wind generation on the Island
 8 Interconnected System to be classified as 22% demand and 78% energy, based on Hydro’s Effective Load
 9 Carrying Capability⁹ Study conducted by Hydro’s resource planning group at the time.

10 In 2025, as part of its continued analysis associated with the *Reliability and Resource Adequacy Review*
 11 proceeding, Hydro engaged an external consultant to study the Effective Load Carrying Capability values
 12 for wind, solar, and battery storage as it applies to the Island Interconnected System for the purpose of
 13 system planning. Hydro filed the study with the Board on December 9, 2025, and it is attached as
 14 Exhibit 16.

15 The 2025 study found that the marginal Effective Load Carrying Capability for 50 MW of wind is 43%
 16 demand, an increase of approximately 20% from the previous 2018 study.¹⁰ Effective Load Carrying

⁸ Please refer to “Load Forecast and Sources of Supply,” Newfoundland and Labrador Hydro, sec. 2.1.2.3. p. 11. Provided as Exhibit 4.

⁹ Effective Load Carrying Capability is a method for capacity accounting to meet resource adequacy.

¹⁰ “Reliability and Resource Adequacy Study,” Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, att. 6.

Capability values are dynamic and can change as resource penetration increases and as the mix of resources on the Island Interconnected System changes.

Hydro is therefore proposing to classify purchases of wind generation on the Island Interconnected System as 43% demand and 57% energy. This proposal is reflected in the 2027 Test Year Cost of Service Study.¹¹

6.4 Rate Mitigation and Calculation of Island Interconnected Customer Rates

6.4.1 Calculation of 2027 Test Year Revenue Requirement

Rates on the Island Interconnected System are mitigated such that retail rate increases to Domestic rate class customers attributable to Hydro's costs shall be targeted at 2.25% per year up to and including 2030. Since Government's rate mitigation plan was announced in May 2024, Hydro and Newfoundland Power have worked together to target this rate increase each July 1. Further information on rate mitigation is included in Chapter 5, Section 5.2.7.

The test year revenue requirement to be used in the calculation of new rates for customers on the Island Interconnected System must be mitigated to comply with the rate mitigation plan. The approach proposed by Hydro to target the 2027 Test Year revenue requirement and rates for July 1, 2027 considers the rate increase target for July 1, 2027, and the necessary input from Newfoundland Power.

Hydro is proposing to calculate the 2027 Test Year revenue requirement for Newfoundland Power based on the forecast rates for July 1, 2026, and to implement a Project Cost Recovery Rider on July 1, 2027, to achieve the targeted 2.25% Domestic rate increase.

The steps to calculate the 2027 Test Year revenue requirement for Newfoundland Power are outlined below. These are completed for the Utility rate, which targets the 2.25% retail Domestic customer rate. Government's rate mitigation plan requires rates for other customers on the Island Interconnected System to be structured in a manner that is compatible with this target rate increase. Therefore, the total rate mitigation for the 2027 Test Year is determined based on the level required to achieve the

¹¹ This proposal was not included in Hydro's Cost of Service Methodology Application filed with the Board in August 2025, as the Effective Load Carrying Capability Study was not complete until the fall of 2025.

2027 Test Year revenue requirement for Newfoundland Power after their allocation based on the 2027 Cost of Service Study. The methodology for determining Newfoundland Power's revenue requirement is:

- 1) Forecast the July 1, 2026 billings at existing rates with the inclusion of the Project Cost Recovery Rider to achieve an average increase in the Utility rate of 3.3%.¹² Please refer to Schedule E-I, page 1, for the calculation.
- 2) Design new base rates to recover the total base rate revenue plus the Project Cost Recovery Rider forecast for July 1, 2026.¹³ Please refer to Schedule E-I, page 2, for the calculation.
- 3) Apply the new base rate to the 2027 billing units. The resulting revenue equals the target test year revenue requirement, net of rate mitigation. Please refer to Schedule E-I, page 3, for the calculation.¹⁴

The total rate mitigation is allocated between customers on the Island Interconnected System based on the methodology proposed in the Cost of Service Methodology Application, including Newfoundland Power, Island Industrial, and Rural Island Interconnected¹⁵ customers. For further details, please refer to the 2027 Test Year Cost of Service Study provided as Schedule F.¹⁶

6.4.2 Revenue Deficiency

Due to the effective date of July 1, 2027 for the implementation of rates, there is a revenue deficiency for the first half of 2027. That deficiency is the result of a delay in the implementation of test year rates, which are designed to recover the annual revenue requirement over twelve months.

During the period from January 1 to June 30, 2027, specifically for Hydro's Utility and Island Industrial customers, a portion of the revenue that would ordinarily be recovered through increased Island

¹² The Utility rate increase of 3.3% on July 1, 2026, is that which is required to target the 2.25% increase to the end customer, as required by the rate mitigation plan.

¹³ July 1, 2026 rates, including riders, will become Hydro's base rates proposed for the 2027 Test Year. The targeted rate increase in accordance with the Government's rate mitigation plan that must be implemented on July 1, 2027, will be proposed separately through Hydro's July 1, 2027 Utility Rate Adjustment Application, through an increase to the Utility Project Cost Recovery Rider at that time.

¹⁴ This schedule also shows the forecast July 1, 2027 rate change, including the 2.25% increase required by the rate mitigation plan. Hydro is only proposing changes to base rates in this application and will propose the 2.25% target rate increase for July 1, 2027 in its July 1, 2027 rate applications.

¹⁵ Rates for Hydro's Rural customers on the Island Interconnected System are also subject to rate mitigation; however, rates for these customers are linked to those for Newfoundland Power customers through Government direction. Accordingly, there are no specific rate proposals for Rural Island Interconnected System customers contained within Hydro's GRA.

¹⁶ The 2027 Test Year Cost of Service Study, excluding rate mitigation, is provided as Schedule G.

Interconnected System base rates related to the 2027 Test Year revenue requirement will continue to be collected through the Project Cost Recovery Rider rather than base rates. Consistent with current regulatory accounting treatment, these revenues will be recorded in Hydro's Supply Cost Variance Deferral Account, which is designed to capture differences between actual costs and amounts recovered in rates associated with Muskrat Falls and related supply costs.

As a result, the revenues collected during the first six months of 2027 will accumulate in the Supply Cost Variance Deferral Account until such time as base rates are formally implemented on July 1, 2027. In substance, the revenue associated with the deficiency identified as resulting from the delay in implementation of test year rates will have already been collected from customers through the Project Cost Recovery Rider increase implemented on July 1, 2026 and deferred in the Supply Cost Variance Deferral Account.

In light of this, Hydro proposes to address the timing-related revenue deficiency through a transfer of the deficiency to the Supply Cost Variance Deferral Account. This approach ensures that the full 2027 Test Year revenue requirement is appropriately recognized and aligns the treatment of collected revenues with the timing of base rate implementation. It also maintains consistency with the established purpose and operation of the Supply Cost Variance Deferral Account, which facilitates the deferral and subsequent disposition of supply-related cost and revenue variances.

Once the 2027 Test Year is approved, transactions starting January 1, 2027 will be recorded in the proposed Long-Term Supply Cost Variance Deferral Account.¹⁷ The variances in this account will be recorded based on 2027 Test Year values instead of 2019 Test Year values, as is the case in the existing Supply Cost Variance Deferral Account, resulting in lower supply cost variances overall. The Long-Term Supply Cost Variance Deferral Account will have the Project Cost Recovery Rider revenue collected from January to June 2027¹⁸ based on rates implemented July 1, 2026. Hydro proposes to use this rider revenue to recover the revenue deficiency.

¹⁷ The revenue deficiency will be transferred to the existing Supply Cost Variance Deferral Account, pending approval of Hydro's Long-term Supply Cost Variance Deferral Account, proposed in this application to be effective January 1, 2027. Upon approval of the Long-Term Supply Cost Variance Deferral Account, Hydro will restate the balance in the existing Supply Cost Variance Deferral Account to reflect the transfer out of balances for the period of January 1, 2027 onwards to the Long-Term Supply Cost Variance Deferral Account.

¹⁸ Project Cost Recovery collections are forecast to be \$76.6 million for Utility and \$6.1 million for Industrial customers.

6.5 Rural Deficit

In the 1970s, Government established several policies which discouraged rate differentials throughout the province, one of which directed that electricity rates charged to rural areas conform to those rates approved for Newfoundland Power customers. Formal direction is provided in OC2003-347.¹⁹ As discussed previously in Chapter 2, Section 2.3.4, revenues from Hydro's Rural customers, with the exception of those on the Labrador Interconnected System, do not fully recover the costs to serve those customers, resulting in a deficit in Hydro's revenue ("Rural Deficit").²⁰

Table 6-3 provides the Rural Deficit for the 2019 Test Year and the 2027 Test Year, in addition to the revenue-to-cost coverage percentages. Revenues forecast to be collected from customers are netted with the costs to serve these customer groups, as calculated based on Hydro's Cost of Service Study, to calculate the Rural Deficit for these areas. Revenue-to-cost coverage represents the percentage of costs that are covered through rates charged to and therefore revenue collected from these customers. Further details can be found in Schedule F. The 2027 Test Year Rural Deficit was calculated using actual revenues and expenses allocated to applicable Rural Deficit areas based on the 2027 Test Year Cost of Service Study allocations.

Table 6-3: Hydro Rural Deficit Estimates

Rural Deficit Areas	2019 Test Year				2027 Test Year			
	Revenues (\$ Millions)	Cost of Service (\$ Millions)	Deficit (\$ Millions)	Revenue to Cost Coverage (%)	Revenues (\$ Millions)	Cost of Service (\$ Millions)	Deficit (\$ Millions)	Revenue to Cost Coverage (%)
Island Interconnected	51.0	73.0	(22.0)	70	68.9	87.3	(18.4)	79
Island Isolated	1.6	10.7	(9.1)	15	1.7	10.4	(8.7)	17
Labrador Isolated	9.0	37.9	(28.9)	24	12.0	44.2	(32.2)	27
L'Anse-au-Loup	3.1	7.4	(4.3)	42	4.1	9.8	(5.7)	42
Total Rural Deficit			(64.3)				(65.0)	

The Rural Deficit remained consistent in the 2027 Test Year, increasing only \$0.7 million over the 2019 Test Year, primarily due to rate mitigation reducing costs on the Island Interconnected System and improved revenue to cost coverage on the Island Interconnected, Island Isolated, and Labrador Isolated

¹⁹ Government of Newfoundland and Labrador, *Order in Council OC2003-346*, July 8, 2003.

²⁰ The Rural Deficit excludes Government departments, which pay full cost rates as approved by the Board.

systems. Hydro files its Rural Deficit report annually, providing details on the initiatives undertaken each year to manage costs that contribute to the Rural Deficit.²¹ Additional information on Hydro's management of the Rural Deficit is contained in Chapter 2, Section 2.3.4.

The Rural Deficit is funded through the rates paid by Newfoundland Power and Hydro's customers on the Labrador Interconnected System. The portion funded by each customer group is determined through test year cost of service studies.²² The corresponding allocation in this application is 96.6% for Newfoundland Power and 3.4% for Rural Labrador Interconnected customers, as outlined in more detail within Schedule F.

6.6 Rate Design for Newfoundland Power

6.6.1 Background

In Board Order No. P.U. 1(2025), the Board approved an update to the wholesale rate charged to Newfoundland Power effective January 1, 2025. The update to the rate structure reflected a change in Hydro's marginal cost of energy, historically based on the cost of fuel at the Holyrood TGS, to the opportunity cost of the market value of exports.

The update to the wholesale rate changed the second block energy rate from 18.165¢ per kWh, which became effective October 1, 2019 when rates were implemented as a result of Hydro's 2017 GRA, to a seasonal second block rate of 9.698¢ per kWh for winter months and 3.354¢ per kWh for the non-winter months. Hydro also changed the first block to a quarterly blocking structure to maintain the same pattern of revenue recognition (power purchase expense for Newfoundland Power) and cash flow as the rate structure approved in the 2017 GRA.

6.6.2 Demand Cost

The current demand charge of \$5.00 per kW per month²³ was approved in the 2017 GRA, giving consideration to marginal capacity costs and the increase in embedded demand costs.

²¹ "2025 Report on the Rural Deficit – Summary of Specific Initiatives," Newfoundland and Labrador Hydro, April 30, 2026. Provided in "2025 Annual Return," Newfoundland and Labrador Hydro, April 30, 2026. Hydro's 2025 Annual Return is confidential pending its presentation in the House of Assembly of Newfoundland and Labrador.

²² Consistent with s. 3(a)(iv) of the *EPCA*, Island Industrial customers do not contribute towards the cost of the Rural Deficit.

²³ Board Order No. P.U. 16(2019).

The average embedded demand cost has increased from \$12.21 per kW per month in the 2019 Test Year Cost of Service Study to \$20.40²⁴ per kW per month in the 2027 Test Year Cost of Service Study.

Hydro is proposing a modest increase in the demand charge for Newfoundland Power of 10%, increasing the demand charge from \$5.00 per kW per month to \$5.50 per kW per month. Hydro believes such an increase will continue to provide the appropriate demand management signal to Newfoundland Power.

6.6.3 First Block Size

As previously mentioned, Hydro implemented a quarterly blocking structure in the wholesale rate charged to Newfoundland Power effective January 1, 2025. Hydro is proposing to revise the existing block structure so that approximately the same proportion of revenue for Hydro (power purchase costs for Newfoundland Power) is reflected in each quarter, based on the 2027 Test Year costs. The existing and proposed block structures are presented in Table 6-4.

**Table 6-4: Existing and Proposed Quarterly Block Structure – Newfoundland Power
(kWh per Month)**

Quarter	Existing Block Structure	2027 Test Year Proposed Block Structure
Q1 – January to March	590,000,000	340,000,000
Q2 – April to June	290,000,000	260,000,000
Q3 – July to September	130,000,000	130,000,000
Q4 – October to December	250,000,000	270,000,000

6.6.4 First Block Energy Rate

The current First Block Energy rate of 8.515 ¢/kWh was proposed in Hydro’s Application for Adjustment to Wholesale Utility Rate filed with the Board on September 25, 2024, and approved in Board Order No. P.U. 1(2025). Hydro is proposing an increase to the First Block Energy rate to 11.815 ¢/kWh.

²⁴ Average embedded cost before Rural Deficit allocation.

6.6.5 Second Block Energy Rate

The current Second Block Energy rate of 9.698 ¢/kWh in winter months and 3.354 ¢/kWh in non-winter months was proposed in Hydro’s Application for Adjustment to Wholesale Utility Rate, approved in Board Order No. P.U. 1(2025).

The Second Block Energy rates proposed for the 2027 Test Year were calculated using the same methodology based on a forecast of Salisbury export prices.²⁵ The methodology is consistent with that approved in Board Order No. P.U. 1(2025). Table 6-5 provides summary results by month.

Table 6-5: 2027 Forecast Seasonal Export Prices (¢ per kWh)²⁶

Month	Price
January	12.684
February	10.193
March	4.414
April	2.596
May	2.334
June	2.820
July	5.130
August	4.519
September	2.899
October	2.991
November	4.550
December	8.539
Winter Average (December–March)	8.958
Non-Winter Average (April–November)	3.480

6.6.6 Proposed 2027 Rate

Table 6-6 provides a summary of the rate structure for Newfoundland Power to recover the 2027 Test Year revenue requirement. The rates reflected in the table are proposed base rates effective January 1, 2027, with proposed implementation on July 1, 2027.

²⁵ Forecast of export prices from Intercontinental Exchange.

²⁶ The seasonal and annual averages of the Salisbury prices for 2027 are based on an hourly price profile, applied to projections on monthly peak and off-peak prices.

Table 6-6: Utility Base Rate Structure

Component	Unit	Existing	2027 Test Year	Comment
Demand	\$/kW/month	5.000	5.500	The proposed rate reflects 10% increase.
1st Block Energy	¢/kWh	8.515	11.815	Rate derived to achieve the revenue requirement after the demand charge and second block rates were calculated.
2nd Block – Winter Energy	¢/kWh	9.698	8.958	Rates calculated based on Hydro's 2027 forecast average marginal cost of energy.
2nd Block – Non-Winter	¢/kWh	3.354	3.480	Rates calculated based on Hydro's 2027 forecast average marginal cost of energy.

6.6.7 Curtailable Credit

Hydro is proposing to continue to provide the curtailable credit in computing the billing demand for Newfoundland Power. The curtailable credit was implemented to ensure curtailable load is available and used efficiently to meet system load requirements. The current credit used to calculate the minimum billing demand is 12 MW.

6.6.8 Firming-Up Charge

Hydro currently has a Firming-Up Charge of 2.882¢ per kWh for firming up secondary energy purchased from CBPP and resold to Newfoundland Power as firm energy. Following the approval of a revised Power Service Agreement in 2021, which eliminated prior generation credit and secondary operating arrangements, and the subsequent approval of stand-alone capacity assistance and CoGen agreements, Hydro no longer relies on secondary power service arrangements associated with CBPP. Due to the change in arrangements with CBPP, Hydro is proposing to eliminate the Firming-Up Charge.

6.7 Rates for Island Industrial Customers

On September 30, 2019, Hydro filed a Wholesale and Island Industrial Rate Design Review Update Report with the Board.²⁷ The purpose of the report was to consider rate design changes that may be

²⁷ "Wholesale and Island Industrial Rate Design Review Update Report," Newfoundland and Labrador Hydro, September 30, 2019.

required for the implementation of rates upon full commissioning of the Muskrat Falls Project. With the commissioning of the Muskrat Falls Project, Hydro's marginal cost of energy moved from No. 6 fuel consumed at the Holyrood TGS to the opportunity cost of the market value of exports. The report proposed the implementation of an energy blocking structure for Island Industrial customers in which the marginal price is based on the market value of exports. Hydro proposed to introduce a two-block energy charge, similar to that of the Utility rate and to maintain the embedded cost-based demand charge. However, for the Industrial customer class, the first block size for each month was proposed to be computed separately for each customer based on each customer's Power on Order multiplied by a specified number of hours.

Under this rate structure, customers who manage their demand effectively and achieve a high load factor would increase their amount of energy use billed on the lower-cost Second Block Energy rate. Customers with lower load factors will have a lower percentage of energy use billed on the lower-cost Second Block Energy rate and a higher percentage of their energy use billed on the higher First Block Energy price.

Hydro more recently asked CA Energy to investigate aspects of an hours of use rate design to update the rate for Industrial customers to a two-block structure with the second block reflecting the opportunity cost of the market value of exports. A copy of the CA Energy Report titled "Pricing for a Revised Island Industrial Rate for Newfoundland and Labrador Hydro" ("Industrial Rate Report") is included as Exhibit 17.

As discussed in the Industrial Rates Report, the hours of use rate design, sometimes termed the Wright rate, is a customer-specific declining block tariff that achieves for rate classes with large variation in customer size what a conventional block design achieves in homogeneous rate classes. A leading example is associated with space heating or air conditioning: the first block price reflects the average cost of serving the customer, excluding the customer charge, while the second block price reflects the cost of providing the incremental energy to serve space heating or cooling. This latter price is often related in some fashion to the marginal cost of adding usage under the relevant weather conditions (e.g., a cold snap for heating or a heat wave for cooling).

1 In rate classes with more diverse customer sizes and end uses, rate blocks cannot readily be defined by
2 kWh boundaries, but can instead be defined on the basis of load factor, or, expressed alternatively, the
3 customer's hours of use. Hours of use can be understood as the number of hours in a month that a
4 customer would need to operate at 100% load factor in order to reach planned or actual consumption. A
5 customer with a 100% load factor records 720 hours of use in a thirty-day month; at a 50% load factor,
6 the customer's hours of use are 360.

7 The hours of use rate is "efficient" in the sense that customers whose usage reaches the second block
8 have access to marginal cost-based pricing. To achieve this level, the customer needs to control its peak
9 demand; an increase in peak demand reduces load factor, hence hours of use, and pushes usage back
10 into the more expensive first block. The first block price is typically higher than that of the second block,
11 since revenue recovery occurs on the first block usage as well as via the customer and demand charges.

12 One strength of the hours of use design is its ability to separate the objective of revenue recovery from
13 that of efficient pricing. The first block price can be set to recover all, or most, fixed costs based on the
14 first block consumption quantity. This quantity in each billing month is a function of the customer's peak
15 demand and the class's load factor (or hours of use). If a customer's peak demand is stable, the first
16 block portion of the bill begins to approximate a customer-specific lump sum. The volumetric portion of
17 the bill becomes the second block energy charge, which is priced at a level based on forecasted marginal
18 cost.

19 The current proposal is consistent with Hydro's 2019 Wholesale and Island Industrial Rate Design Review
20 Update Report, with the exception of the fact that the first block size for each month was proposed to
21 be computed separately for each customer based on each customer's Power on Order multiplied by a
22 specified number of hours. CA Energy discussed this concept in the Industrial Rate Report, noting that
23 Hydro could choose to make the hours of use design customer-specific with respect to the block
24 boundary, which could be of interest as Hydro's customers' load factors vary widely. Four of Hydro's six
25 Island Industrial customers' load factors lie between 60% and 85%. The remaining customers have load
26 factors of about 45%. CA Energy noted:

27 However, this approach has an incentive problem in that a customer whose load factor
28 declines in one year expect relief against load factor reduction by means of adjustment
29 of the block boundary to reflect their reduced load factor. For example, a customer with

a 60% load factor and a block boundary of 90% of that load factor could have their load factor diminish to 50% and still in the next year have the same percentage of their load in Block 2. To oppose this incentive, the utility might require that a customer have a minimum load factor, adjustable only with a lag. While such an approach is feasible, it is potentially administratively burdensome. The combination of the incentives problem and the potential administrative complications suggest that the utility might prefer the class-wide approach, provided that selection of an HOU block boundary still permits customers to reach the second energy block in most months.²⁸

As outlined in the Industrial Rate Report, Hydro and CA Energy examined the impact of a number of hours of use boundaries, using customer-specific data to analyze customer impacts of each boundary level. For the hours of use design to be effective, customers must achieve usage in the second block in most months. For the 300-hour block boundary, CA Energy’s analysis found that this block size was sufficient to allow most customers in most months to achieve usage in the second block and thereby be exposed to marginal cost-based incremental energy prices with modest overall billing impacts.

6.7.1 Demand Rate

The current demand charge of \$10.73 per kW per month was the average embedded demand cost in the 2019 Test Year Cost of Service Study. The current average embedded demand cost in the 2027 Test Year Cost of Service Study is \$17.54 per kW per month. As described in the Industrial Rate Report, a pure hours of use design lacks a demand charge, with the burden of recovering demand-related costs falling to the first block energy price. A variant of this would be to reduce the demand charge and shift the revenue recovery to the first block energy price. This would shift the design in the direction of a “pure” hours of use structure, but would likely not alter the amount of revenue recovered from the customer, assuming that they have some second block usage. Either design allows for the cost recovery required by Hydro. Continuing with a demand charge in the rate design for Island Industrial customers also keeps the consistency with that of Hydro’s Utility customer rate.

Hydro is proposing to maintain a demand charge of \$5.50 per kW per month, equivalent to that proposed for Newfoundland Power. The proposed demand rate will recover approximately 31% of the embedded demand costs from Island Industrial customers and 27% from Newfoundland Power, with the remainder recovered in the first block rates.

²⁸ “Pricing for a Revised Island Industrial Rate for Newfoundland and Labrador Hydro,” Christensen Associates Energy Consulting, May 11, 2026, p. 5. Provided as Exhibit 17.

6.7.2 First Block Energy Rate

Based on selecting an hours of use rate design with a \$5.50 per kW demand price and a 300-hours of use block boundary, Hydro is proposing a First Block Energy rate of 6.694 cents per kWh.

6.7.3 Second Block Energy Rate

The Second Block Energy price is calculated based on the forecast export prices on a seasonal basis.²⁹

The seasons are currently defined for the Utility customer, with winter covering December to March and all other months being non-winter; the same is proposed for the Island Industrial customers.

Table 6-7 provides a comparison of the existing and proposed final demand and energy base rates for Island Industrial customers based on the 2027 Test Year.

Table 6-7: Industrial Customer Demand and Energy Charges

	Existing	Proposed
Demand charge (\$/kW/month)	10.73	5.50
Energy charge (¢ per kWh)	4.428	
First Block (¢ per kWh)		6.694
Second Block		
Winter – December to March (¢/kWh)		8.889
Non-Winter – April to November (¢/kWh)		3.285

6.7.4 Specifically Assigned Charges

The Island Industrial Customer rate also includes a customer-specific charge, or specifically assigned charge, which is designed to recover the costs of any transmission facilities specific to providing service to a single Industrial customer.³⁰

The proposed cost allocation for operating expenses³¹ utilizes actual operating and maintenance costs, comprised of a Direct Operating and Maintenance Charge calculated as the six-year average of actual

²⁹ The second block prices were calculated by CA Energy using Hydro's forecast export prices for 2027. Please refer to Exhibit 17. The pricing methodology is consistent with the approved in Board Order No. P.U. 1(2025) to update the wholesale utility rate charged to Newfoundland Power. Differences in the resulting rates for the utility rate charge to Newfoundland Power and the Island Industrial customers are due to load profiles.

³⁰ Specifically assigned charges include operating and maintenance costs, return on debt and equity, and depreciation. For customers who make CIAC for the assets, the specifically assigned charge is based on the estimated operating and maintenance cost for the specifically assigned asset.

³¹ Proposed as part of Hydro's 2025 Cost of Service Methodology Application.

operating and maintenance expenses recorded against each specifically assigned asset, or estimated costs where historical costs are not available, and an Indirect Operating and Maintenance Charge calculated as the ratio of total indirect transmission operating and maintenance to total direct transmission operating and maintenance, derived from the Cost of Service Study.

Specifically assigned charges recover costs incurred for assets that are in service solely for each Island Industrial Customer.³² Table 6-8 provides a comparison of the existing and proposed specifically assigned charges by customer.

Table 6-8: Industrial Customer Specifically Assigned Charges (\$)

Customer	Approved	Proposed
CBPP	13,311	5,822
Braya	107,678	103,152
Marathon	-	9,302
Teck	51,789	9,950
Vale	145,352	285,041
Total	318,130	413,267

6.7.5 Island Industrial Customer Rate Impacts

As outlined in Section 6.4.1, the total rate mitigation for the 2027 Test Year is determined based on the level of rate mitigation calculated to achieve the 2027 Test Year revenue requirement for Newfoundland Power and is shared between all customer groups on the Island Interconnected System, including Industrial customers. The revenue requirement for Industrial customers of \$42.8 million is calculated through the allocation of costs based on the previously approved cost of service methodology, the cost of service methodology proposed in Hydro's 2025 Cost of Service Methodology Application,³³ and the methodology proposed in this application, including the allocated portion of rate mitigation.

Hydro implemented the Project Cost Recovery Rider for Island Industrial customers on January 1, 2024 as an increase to rates to include recovery of a portion of the Muskrat Falls Project costs. As shown in Table 6-9, the total of the existing base rate revenue and the Project Cost Recovery Rider results in

³² For the Newfoundland Power rate design, there is no specifically assigned charge, as these costs are blended in the second block energy charge, which is priced to reflect the marginal cost of exports.

³³ An agreement has been reached with the intervenors to the 2025 Cost of Service Methodology Application regarding the majority of proposals made by Hydro in that application.

1 annual billings of \$51.6 million.³⁴ This is greater than the annual revenue requirement of \$42.8 million
2 calculated in the 2027 Cost of Service Study for Industrial customers, indicating that the total billings for
3 Industrial customers should be reduced in 2027. Such changes are not unexpected given the lengthy
4 period since the previous GRA and that this is the first Cost of Service Study reflecting Muskrat Falls
5 Project costs and rate mitigation. Hydro proposes to implement new base rates to recover the revenue
6 requirement of \$42.8 million reflecting the 2027 Cost of Service Study.

7 Hydro intends to apply in 2027 to utilize the Project Cost Recovery Rider to target the annual rate
8 increase on July 1, 2027, currently estimated at 3.3%.³⁵ The inclusion of the Project Cost Recovery Rider
9 for the Island Industrial Customers is consistent with the approach utilized for Newfoundland Power
10 where the Project Cost Recovery Rider is used to target the annual rate increase. It is also consistent
11 with the rate mitigation plan, which directs rates for other customers subject to Island Interconnected
12 rates shall be targeted in a manner that is compatible with the Hydro Target Rate Increase.³⁶ The
13 estimated rate change on July 1, 2027, as a result of the combined impact of the 2027 Test Year revenue
14 requirement and the rider that will be proposed for the July 1, 2027 rate adjustment is a rate reduction
15 of 14.3% compared to existing rates.³⁷ A comparison of existing to proposed rates is provided in
16 Table 6-9.³⁸

³⁴ The CDM Recovery Adjustment collects annual activity in the CDM Cost Deferral Account over a ten-year period. These costs are not included in the Cost of Service.

³⁵ The actual rate is calculated based on the wholesale rate increase to Newfoundland Power as determined in April each year.

³⁶ Rate increases to Domestic class customers attributable to Hydro shall be targeted at 2.25% per year.

³⁷ Base rates and Specifically Assigned charges increased by 6.9% combined, offset by a reduction in the Project Cost Recovery Rider of 21.2%.

³⁸ Table 6-9 compares revenues under current rates to rates proposed using the Hours of Use Rate Design. The existing structure updated with 2027 rates would equal the same \$42.8 million calculated using Hours of Use (Demand – 1,095,600 x 17.54 \$/kW/mo = \$19.2 + Energy 613,371 MWh x 3.780 ¢/kWh = \$23.2 + Specifically Assigned = \$0.4).

Table 6-9: Customer Rate Impacts – Proposed July 1, 2027 Rate
Island Industrial Customers³⁹

	Billing Units ⁴⁰	Unit	Current Rates	Billings at Existing Rates (\$)	Proposed Rates ⁴¹	Revised Billings (\$)	Change (\$)	Change (%)
Demand (kW/s)	1,095,600	\$/kW/mo	10.73	11,755,788	5.50	6,025,800		
Energy - Firm (MWh/s)	613,371	¢/kWh	4.428	27,160,083	-	-		
First Block Energy	326,360	¢/kWh			6.694	21,846,538		
Second Block - Winter Energy	91,034	¢/kWh			8.889	8,092,012		
Second Block - Non-Winter Energy	195,977	¢/kWh			3.285	6,437,844		
Specifically Assigned		\$	318,130	318,130	413,404	413,404		
Total Base Rate				39,234,001		42,815,599	3,581,598	6.9%
Project Cost Recovery Rider	613,371	¢/kWh	2.015	12,359,433	0.230	1,410,754	(10,948,678)	-21.2%
CDM Recovery Adjustment	613,371	¢/kWh	0.007	42,936	0.007	42,936	-	0.0%
Total				51,636,369		44,269,289	(7,367,080)	-14.3%

1 **6.7.6 Non-Firm Rate**

2 The Island Industrial Customer contracts currently include a provision for interruptible demand. The
3 2027 Test Year Cost of Service Study does not include interruptible demand in determining the peak
4 demand for the Island Industrial Customer class for cost allocation. The interruptible demand reflects
5 the non-firm load requirement in the standard Island Industrial Customer contracts. When customers
6 are using interruptible demand, they are generally required to pay for their additional energy
7 requirements based on the market value of exports.

8 Thermal sources can still be the marginal supply for non-firm energy, such as when the Holyrood TGS is
9 being operated to provide energy to the Island Interconnected System. For non-firm service, where
10 thermal is the marginal source, Hydro is proposing to retain the previously approved calculation for the

³⁹ Numbers may not add due to rounding.

⁴⁰ 2027 Forecast.

⁴¹ There is no increase to the Project Cost Recovery Rider as of July 1, 2027 being proposed within Hydro's 2026 GRA. This is forecast and actuals may differ. Adjustments to the Project Cost Recovery Rider for July 1, 2027 will be proposed in Hydro's application for approval of Island Industrial Customer Rate Adjustments effective July 1, 2027.

energy charge with an update to the loss factors. The loss factor has been updated to the five-year⁴² average Island Interconnected System losses from 3.34% to 3.44%.

6.7.7 Industrial Wheeling

In the 2019 Test Year, the wheeling rate was updated, even though no customers were accessing the rate, until it was replaced with the implementation of an open access tariff. Rates for open access were approved in Board Order No. P.U.3(2018) and updated in Board Order No. P.U.3(2021).

Hydro is proposing to discontinue the wheeling rate for Island Industrial customers, as open access tariff rates have been implemented.

6.8 Rates for Rural Customers

For rate-setting purposes, there are three distinct groups of Rural customers:

- 1) Island Interconnected and L'Anse-au-Loup systems;
- 2) Isolated systems; and
- 3) Labrador Interconnected System.

Rates proposed in this application for Rural customers are based upon the policies for Hydro Rural rates as approved in Board Order No. P.U. 14(2007) and set out in Section 16 of Hydro's Schedule of Rates, Rules and Regulations, *Policies for Automatic Rate Changes*, as well as Government direction through various OCs such as OC2006-512. Hydro is proposing to apply the same increase to all classes of service on the Labrador Interconnected System, with the exception of Street and Area Lighting. The calculated average rate increase for Labrador Interconnected rates is 8.54%; however, with the support of Government,⁴³ Hydro is proposing to apply an annual average increase of 2.25% to each rate class over four years, with the exception of Street and Area Lighting, to phase in this rate increase.

Excluding Government departments in isolated diesel areas, rates for Rural customers on the Island Interconnected, L'Anse-au-Loup, and Isolated systems, including preferential rate customers, will continue to be based on Newfoundland Power rates.

⁴² 2020 to 2024.

⁴³ Please refer to Exhibit 18.

Rates for Government departments in isolated diesel areas will continue to be based on full cost recovery. These proposals are more fully outlined in the Rural Deficit in Section 6.5.

6.8.1 Island Interconnected and L’Anse-au-Loup Systems

Hydro’s rates for Rural customers on the Island Interconnected and L’Anse-au-Loup systems are the same as the rates charged to Newfoundland Power customers. It is estimated that Hydro’s proposed rates for Newfoundland Power will see a flow-through increase for these customers of approximately 2.3% effective July 1, 2027, compared to the rates that will become effective on July 1, 2026, subject to Board approval.

The Burgeo School and Library rate is increased or decreased by the average rate of change granted to Newfoundland Power, excluding Newfoundland Power’s changes for the July 1 Municipal Tax and Rate Stabilization Adjustments.

6.8.2 Isolated Systems

For rate-setting purposes, there are three customer groups in the Isolated systems:

- 1) Rural Domestic customers, excluding Government departments;
- 2) Rural General Service customers, excluding Government departments; and
- 3) Government departments.

Hydro’s rates for Rural Domestic customers, excluding Government departments, are the same as Newfoundland Power’s rates for the basic customer charge and first block consumption (lifeline consumption), but non-lifeline consumption is adjusted by the average rate of change granted to Newfoundland Power.⁴⁴

Rates for Rural General Service customers on the Isolated systems are normally adjusted by the average rate of change approved for the customers of Newfoundland Power.

Government rate classes in isolated systems pay cost-based rates, and Hydro proposes that the 2027 Test Year cost recovery level for Government departments remains at 100%. Hydro is proposing an

⁴⁴ The lifeline block is designed to provide Domestic customers with access to electricity at non-discriminatory prices for essential services. Essential services include most electrical appliances and hot water heating, but not electric heat.

increase of 13% in Government rates to become effective July 1, 2027. Schedule E-III provides a comparison of rates effective July 1, 2026, to the proposed rates to become effective July 1, 2027.

6.8.3 Labrador Interconnected System

The average rate increase for rural Labrador Interconnected customers based on the 2027 Cost of Service Study is 8.54%. Government has advised that it supports a rate smoothing approach by Hydro to ease cost-of-living pressures for customers. In particular Government supports the phase-in of the proposed rate increase for Rural Labrador Interconnected customers at an average increase per rate class of 2.25% per year over four years, with the first rate increase effective July 1, 2027 for all Hydro Rural classes on the Labrador Interconnected System with the exception of Street and Area Lighting.⁴⁵ Hydro has outlined the proposed average customer rates calculated based on a 2.25% increase over four years starting in 2027 in Schedule E-III, with the first increase proposed herein to be implemented on July 1, 2027. Subsequent increases will be proposed annually for approval by the Board to be effective July 1 each year. At the end of the four years, Hydro is projecting a residual revenue deficiency of approximately \$3.3 million and proposes that this residual revenue deficiency be addressed as part of Hydro's next GRA,⁴⁶ or in a separate application at that time. Table 6-10 outlines the projected revenue deficiency in each year associated with the 2.25% phase in, along with the cumulative residual revenue deficiency at the end of the four years.

**Table 6-10: Projected Revenue Deficiency –
 Labrador Rural Interconnected Phase In
 (\$ Millions)**

Year	Revenue Deficiency
2027	1.5
2028	1.1
2029	0.6
2030	0.1
Cumulative Revenue Deficiency	3.3

⁴⁵ Supply costs which are not recovered through rates given rate smoothing proposed will be captured in Hydro's proposed Rural Labrador Interconnected – Revenue Deficiency Deferral Account, as further described in Section 6.10.3.

⁴⁶ Hydro is proposing that its next rate-setting year be 2031.

In its 2021 CBA, Hydro proposed to convert all existing HPS streetlights to LED streetlights.⁴⁷ By 2027, the project will be complete, and it is projected that there will be 2,240 LED streetlights on the Labrador Interconnected System.

Hydro has designed a new rate for LED streetlights that provides full cost recovery. Therefore, the rates proposed to be effective on July 1, 2027 for Street and Area Lighting rates on the Labrador Interconnected System will remain in effect until the next GRA. A calculation of the proposed rates for each fixture is included in Schedule E-II.

The proposed rates to become effective July 1, 2027, are provided in Schedule E-III and provide a comparison of the existing and proposed rates for Rural customers on the Labrador Interconnected System and Government Diesel customers.

6.9 Labrador Industrial Customers

6.9.1 Rate Structure

Labrador Industrial customers are charged separate rates for the generation and transmission of electricity. The rates are further classified as energy rates and demand rates, with some components regulated and some non-regulated.

The rates to recover generation costs from Industrial customers in Labrador are not governed by the *Act* and require consideration of competitiveness with other jurisdictions.⁴⁸ In accordance with Government policy, the Firm Energy rates are updated annually and are non-regulated. The Firm Generation Demand rate is considered non-regulated and is based on Hydro's average cost per kW incurred to provide standby generation⁴⁹ on the Labrador Interconnected System, it is updated at the conclusion of Hydro's GRA process.⁵⁰

⁴⁷ "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. November 2, 2020 (originally filed August 2, 2020), vol. I, sec. C, Distribution In-Service Failures, Miscellaneous Upgrades, and Street Light Modernization.

⁴⁸ As the *Act* does not apply, pursuant to Section 5.8(2) of the *EPCA*, the generation component of the rates does not require the approval of the Board. The Generation Demand rate, while not specifically approved by the Board, is based on the costs approved by the Board in Hydro's most recent test year Cost of Service.

⁴⁹ Standby generation refers to the Labrador Industrial customers' portion of costs associated with the Happy Valley GT, operated to provide reliability for all customers on the Labrador Interconnected System.

⁵⁰ The Generation Demand rate is based on costs that are allocated to Labrador Industrial customers in the Board-approved test year Cost of Service Study. The current Generation Demand rate of \$0.41 per kW per month was implemented on October 1, 2019, and will remain in effect until new rates are implemented.

Transmission costs are recovered through a Transmission Demand rate, to which the Act applies and therefore must be approved by the Board. The Transmission Demand rate currently in effect is \$1.08 per kW per month.⁵¹ The average embedded cost for transmission demand allocated to Labrador Industrial customers has increased from \$1.08 per kW per month for the 2019 Test Year to \$2.00 per kW per month for the 2027 Test Year. The increase results from additional transmission investment over an eight-year period on the Labrador Interconnected System, reflected in the 2027 Test Year, compared to the 2019 Test Year, as well as an increase in cost allocated to this customer class due to increased load compared to the 2019 Test Year.

The demand rate is designed to provide recovery of capacity-related transmission and standby generation costs on the Labrador Interconnected System. While the Generation Demand rate is not explicitly approved by the Board, the standby generation⁵² demand costs used by Hydro to derive the rate reflect Hydro's approved costs in its most recent GRA. The generation demand costs allocated to Labrador Industrial customers is \$0.40 per kW per month for the 2027 Test Year, compared to \$0.41 per kW per month in the 2019 Test Year. These costs are recorded by Hydro as a cost recovery and included in Other Revenues.

The overall Labrador Industrial customer demand rate is therefore proposed to increase from \$1.49 per kW per month in the 2019 Test Year to \$2.40 per kW per month in the 2027 Test Year. This results in an estimated overall billing impact, including regulated and non-regulated charges, to Labrador Industrial customers of 6.1%.⁵³ Even with this increase, when compared to Industrial rates across other Canadian jurisdictions, Labrador Industrial rates continue to be the lowest in the country.

6.9.2 Specifically Assigned Charges

The Board may approve fixed charges to recover the cost of providing transmission assets that are specific to providing service to a single Industrial customer. While the capital costs of these investments have been funded by the Labrador Industrial customers served by the transmission assets, Hydro

⁵¹ The current rate of \$1.08 per kW per month was implemented on October 1, 2019, as a result of the Board's approval of Hydro's 2017 GRA in Board Order No. P.U. 30(2019) and will remain in effect until new rates are implemented.

⁵² Standby generation refers to the Labrador Industrial customers' portion of costs associated with the Happy Valley GT, operated to provide reliability for all customers on the Labrador Interconnected System.

⁵³ Based on 2026 forecast billing units and existing January 1, 2026 energy rates, and includes specifically assigned charges and revenue deficiency.

proposes a specifically assigned charge to recover the operating and maintenance costs associated with the specifically assigned transmission assets, consistent with that described above for Island Industrial customers. The specifically assigned charges proposed to be recovered from Tacora and IOC annually are \$11,058 and \$33,697, respectively.

6.10 Revenue Deficiencies

Hydro is proposing final rates based on a 2027 Test Year with anticipated rate implementation on July 1, 2027. Implementation of rates on July 1 results in a revenue deficiency for the first six months of 2027. In addition, Hydro is proposing to phase in the calculated rate increase for Rural Labrador Interconnected customers at 2.25% per year, over four years, resulting in a further revenue deficiency for this customer group. Hydro's proposal for recovery of revenue deficiencies varies by customer based on rate proposals previously mentioned and are outlined in Exhibit 19.

6.10.1 Newfoundland Power

Newfoundland Power's rates are subject to the rate mitigation plan, with rates increasing annually on July 1 to target a 2.25% increase to Domestic customers. As described in Section 6.4, an equivalent amount to the base rates proposed within this application to be effective July 1, 2027, will be in effect as of July 1, 2026, through the combination of the July 1, 2026 base rates and the Project Cost Recovery Rider, and will be recorded in the Supply Cost Variance Deferral Account under the Project Cost Recovery Rider – Utility amount. Therefore, as outlined in Section 6.4.2, Hydro proposes to address the timing-related revenue deficiency of \$60.1 million by transferring the amount to the Supply Cost Variance Deferral Account, thereby aligning the recognition of revenues with the timing of base rate implementation and ensuring appropriate recovery of the 2027 Test Year revenue requirement.

6.10.2 Island Industrial Customers

Island Industrial customers' rates are subject to the rate mitigation plan, with rate increases structured in a manner that is compatible with the target rate increase of 2.25% per year for Domestic rate class customers attributable to Hydro's costs. Island Industrial customer rates will be designed to recover the 2027 Test Year revenue requirement, which is determined after rate mitigation has been applied to target Newfoundland Power's revenue requirement. Similar to Newfoundland Power, Island Industrial customers have been paying a Project Cost Recovery Rider, implemented on July 1, 2026, which recovers project costs. Therefore, Hydro proposes to address the revenue deficiency of \$2.7 million by

transferring the amount to the Supply Cost Variance Deferral Account, ensuring recovery of the 2027 Test Year revenue requirement.

6.10.3 Government Diesel Customers

Government customers on the Isolated Diesel systems rates are proposed to increase by approximately 13%, resulting in a revenue deficiency of \$165,000. Hydro is proposing to amortize this deficiency over a period of 42 months and recover from customers through increased rates proposed herein.

6.10.4 Rural Labrador Interconnected

The calculated increase in rates for Rural Labrador Interconnected customers is approximately 8.54%. Government has expressed its support for the phase-in of the rate increase at 2.25% per year, over four years, with the first increase implemented on July 1, 2027 for all rate classes except for Street and Area Lighting.⁵⁴ The revenue deficiency with the projected rate increase of 8.54% on July 1, 2027 is approximately \$1.7 million; the revenue deficiency complying with the Government request to phase in the rate increase is approximately \$1.5 million.

Hydro is proposing a Rural Labrador Interconnected – Revenue Deficiency Deferral Account to record the revenue deficiency/sufficiency each month until the balance in the account is settled. The proposed deferral account definition is included within Exhibit 10.

6.10.5 Labrador Industrial Customers

The demand rate for Labrador Industrial customers is proposed to increase from \$1.49 kW per month to \$2.40 kW per month, to be implemented July 1, 2027, resulting in a revenue deficiency of approximately \$1.8 million for the first six months of 2027. Hydro is proposing to amortize this deficiency over a period of 42 months and implement a GRA Recovery Rider on customers' monthly bills to recover the balance.

The monthly customer rider amount is proposed to remain constant over the 42-month recovery period, determined by the following formula:

GRA Recovery Rider for Labrador Industrial Customers = (2027 Test Year Customer Firm Billing Demand / 2027 Test Year Total Firm Billing Demand) x Monthly Recoverable Amount.

⁵⁴ The calculated rate increase for Street and Area Lighting is less than 2.25%, and therefore, the rate increase will be based on cost, as noted above.

6.11 Hydro's Application

6.11.1 Rules and Regulations

Hydro is proposing the following changes in its Rules and Regulations to become effective July 1, 2027:

- Modify the definition of “Generation Credit” to reflect the change in calculation of the hydraulic credit, testing requirements for thermal and hydraulic and criteria for the generation credit reflected in billing demand.

Hydro's proposed amendment to the Schedule of Rates, Rules and Regulations – Utility Definitions has been included as Exhibit 20.

6.11.2 Cost of Service

Hydro is requesting Board approval of the following aspects of its Cost of Service Methodology:

- The implementation of a 64 MW Hydraulic Credit for Newfoundland Power, with the process for the determination of the thermal generation credit to remain unchanged.
- The continuation of the cost of service treatment approved in Board Order No. P.U. 30(2019) for the Holyrood TGS and Holyrood TGS fuel costs, including:
 - The classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor; and
 - Holyrood TGS fuel costs be classified as 100% energy.
- The classification of purchases of wind generation on the Island Interconnected System as 43% demand and 57% energy.

6.11.3 Rates for Newfoundland Power

Hydro is requesting the Board's approval for the following changes with respect to the rates and rate design for Newfoundland Power, to become effective July 1, 2027:

- Demand Charge of \$5.50 per kW of billing demand per month;
- A revision to the existing block structure, as outlined in Table 6-4, so that approximately the same proportion of revenue (power purchase costs for Newfoundland Power) is reflected in each quarter based on 2027 Test Year costs;

- An increase in the First Block Energy rate to 11.815 cents per kWh;
- A decrease in the Second Block Winter Energy rate to 8.958 cents per kWh;
- An increase in the Second Block Non-Winter Energy rate to 3.480 cents per kWh;
- Transfer of the Revenue Deficiency of \$60.1 million to the Supply Cost Variance Deferral Account; and
- Eliminate the Firming-Up Charge.

6.11.4 Rate Design for Island Industrial Customers

Hydro is requesting the Board's approval for the following changes with respect to the rates and rate design for Island Industrial customers, to become effective July 1, 2027:

- The implementation of hours of use rate design, utilizing a 300-hours of use block structure;
- A Demand charge of \$5.50 per kW of billing demand per month;
- First Block rate of 6.694 cents per kWh;
- A seasonal energy second block price for winter of 8.889 cents per kWh;
- A seasonal energy second block price for non-winter of 3.285 cents per kWh;
- Transfer of the Revenue Deficiency of \$2.7 million to the Supply Cost Variance Deferral Account;
- Annual Specifically Assigned charges as follows:
 - CBPP – \$5,822;
 - Braya – \$103,152;
 - Marathon – \$9,302;
 - Teck – \$9,950; and
 - Vale – \$285,041.
- Continue the previously approved calculation for the non-firm energy charge with an update for the loss factor to the five-year average Island Interconnected System losses, from 3.34% to 3.44%; and

- Discontinue the Island Industrial Wheeling rate, given that open access tariff rates have been implemented.

6.11.5 Rates for Rural Customers

Hydro is requesting that the Board approve the following proposal effective July 1, 2027:

- Rates for Isolated Rural customers – Government as provided in Schedule E-III, reflecting an increase of 13%; and
- Rates for Labrador Interconnected Rural customers as provided in Schedule E-III, reflecting a phase-in approach to the 2027 Test Year rate increase at 2.25% per year over four years, with the exception of LED Streetlights;
- Amortization of the Revenue Deficiency of \$165,000 associated with Government Diesel Customers over a period of 42 months to be recovered from customers through increased base rates; and
- Creation of a Revenue Deficiency deferral account for Labrador Interconnected Rural Customers with the definition as provided in Exhibit 10 to capture revenue deficiency associated with the phase-in approach to the 2027 Test Year rate increase for Labrador Interconnected Rural customers.

6.11.6 Rates for Labrador Industrial Customers

Hydro is requesting that the Board approve the following proposal effective July 1, 2027:

- Proposed regulated transmission demand rate for Labrador Industrial customers provided in Schedule E-III;
- Amortization of the Revenue Deficiency of \$1.8 million over a period of 42 months through the implementation of a GRA Recovery Rider designed to collect \$42,000 per month; and
- Specifically Assigned charges for each customer as follows:
 - Tacora – \$11,058; and
 - IOC – \$33,697.

6.12 Conclusion

Hydro believes that the proposed rates and rate design changes, taken together, appropriately balance the objectives of cost recovery, customer affordability, rate stability, and regulatory efficiency, and are reasonable and necessary in light of Hydro's legislated mandate and current operating environment.

Overall, Hydro's proposals present an evidence-based approach to cost recovery and rate design that balances rate mitigation commitments, regulatory consistency, and appropriate pricing signals across the Island Interconnected and Labrador systems.

Schedule A



Schedule A-I
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Newfoundland and Labrador Hydro
Schedule A-I: Actual and Forecast Electricity Requirements for 2019–2027¹
Island Interconnected System

	2019 Test Year		2019 Actual		2020 Actual		2021 Actual		2022 Actual		2023 Actual		2024 Actual		2025 Forecast ²		2026 Forecast ³		2027 Test Year ³	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW ⁴	GWh	MW ⁴	GWh
Newfoundland Power ⁵	1,322.7	5,800.7	1,405.7	5,926.0	1,280.1	5,529.0	1,201.0	5,432.4	1,258.3	5,508.8	1,365.9	5,858.3	1,423.4	5,701.6	1,367.3	5,845.8	1,440.6	6,032.3	1,450.3	6,014.6
Industrial Customers ⁶	96.5	743.3	92.0	617.9	90.0	453.1	71.3	421.9	68.2	387.4	66.8	334.3	91.0	448.8	91.6	491.2	84.7	613.4	91.3	613.4
Hydro Rural Interconnected	96.9	451.5	95.4	477.7	93.6	446.6	83.2	442.7	91.4	454.9	101.2	445.9	94.8	434.9	95.7	459.0	95.3	464.1	94.9	461.6
Total Deliveries⁷	1,488.0	6,995.5	1,580.2	7,021.6	1,447.5	6,428.7	1,327.2	6,297.0	1,404.9	6,351.2	1,532.4	6,638.5	1,562.9	6,585.4	1,518.3	6,796.0	1,598.4	7,109.7	1,613.3	7,089.6
Transmission Losses ^{7,8}	79.0	206.9	71.1	216.4	68.0	234.7	73.8	227.3	61.4	228.3	74.4	232.1	73.7	273.0	62.3	320.6	70.4	372.8	70.4	327.3
Total Hydro Island Interconnected System Electricity Requirement⁹	1,567.0	7,202.4	1,651.3	7,238.0	1,515.6	6,663.4	1,401.0	6,524.3	1,466.4	6,579.4	1,606.8	6,870.6	1,636.6	6,858.4	1,580.5	7,116.7	1,668.8	7,482.5	1,683.7	7,416.9

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ The 2026 and 2027 Forecast is sourced to the June 2025 Island Operating Load Forecast.

⁴ Forecast transmission losses at peak include 35.2 MW of station service load.

⁵ Newfoundland Power MW reflect the maximum annual MW purchased by Newfoundland Power from Hydro.

⁶ Industrial MW for 2019–2025 actuals reflect the sum of annual maximum customer demands (not power on order - actual maximums).

⁷ MWs for total deliveries and transmission losses are coincident with system peak. MW transmission losses include Hydro's station services.

⁸ MW Transmission losses include the station service requirements for Holyrood, Bottom Brook, and Soldiers Pond as appropriate (i.e., includes LIL losses).

⁹ Hydro's requirement MW are Hydro's system coincident MW and include customer firm demand requirements only. Forecast MW are annual maximums.

Schedule A-II
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Newfoundland and Labrador Hydro
Schedule A-II: Actual and Forecast Electricity Requirements for 2019–2027¹
Labrador Interconnected System

	2019 Test Year		2019 Actual ²		2020 Actual ²		2021 Actual ²		2022 Actual ²		2023 Actual ²		2024 Actual ²		2025 Forecast ³		2026 Forecast ⁴		2027 Test Year ⁴	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected	171.2	752.7	157.2	710.2	154.8	677.8	148.5	673.7	161.4	736.4	167.1	730.9	170.8	698.2	169.7	693.9	166.8	728.0	168.9	735.8
Department of National Defence ⁵	-	-	-	0.1	-	0.1	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Customers																				
Iron Ore Company of Canada	240.0	1,740.6	250.7	1,658.3	245.4	1,659.9	245.3	1,589.7	238.9	1,618.2	246.5	1,461.3	255.3	1,547.8	248.5	1,554.4	262.0	1,575.4	262.0	1,575.4
Tacora Resources Inc.	53.0	285.4	50.5	160.0	53.4	343.0	53.7	312.4	58.0	342.4	51.1	336.8	54.8	316.4	55.1	310.9	55.0	327.0	55.0	327.0
Total Industrial Customers	293.0	2,026.0	301.1	1,818.3	298.8	2,002.9	299.0	1,902.2	297.0	1,960.6	297.7	1,798.0	310.1	1,864.1	303.6	1,865.3	317.0	1,902.4	317.0	1,902.4
Total Deliveries⁶	410.1	2,778.7	400.8	2,528.6	441.5	2,680.8	409.0	2,575.9	432.8	2,697.1	422.4	2,528.9	443.5	2,562.3	429.2	2,559.2	450.1	2,630.3	452.0	2,638.2
Transmission Losses ⁶	34.2	191.9	31.5	165.5	33.9	180.5	30.0	163.5	11.6	158.8	15.3	134.3	5.9	155.9	11.8	134.7	27.6	181.8	28.2	171.9
Total Hydro Labrador Interconnected System Electricity Requirement	444.3	2,970.6	432.3	2,694.1	475.4	2,861.4	438.9	2,739.4	444.4	2,855.9	437.7	2,663.2	449.5	2,718.2	441.0	2,693.8	477.7	2,812.1	480.2	2,810.1

¹ Numbers may not add due to rounding.

² Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load.

³ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

⁴ The 2026 and 2027 Forecast is sourced to the June 2025 Labrador Operating Load Forecast.

⁵ Sales to Canadian Forces Base Goose Bay are secondary sales.

⁶ Demands for total deliveries and transmission losses are coincident with the system peak.

Schedule A-III
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Newfoundland and Labrador Hydro
Schedule A-III: Actual and Forecast Electricity Requirements for 2019–2027¹
Isolated Systems

	2019 Test Year		2019 Actual		2020 Actual		2021 Actual		2022 Actual		2023 Actual		2024 Actual		2025 Forecast ²		2026 Forecast ³		2027 Test Year ³	
	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵	kW ⁴	MWh ⁵
Labrador																				
L'Anse-au-Loup	6,105.4	26,987.9	5,650.0	25,468.6	5,444.0	25,022.5	5,754.0	24,759.4	5,693.0	25,553.2	5,996.0	25,918.4	5,765.0	25,860.7	5,765.0	26,261.1	6,054.8	26,838.6	6,104.8	27,046.6
Labrador Isolated Systems	10,900.7	46,342.5	10,027.0	43,467.9	9,954.0	41,953.8	10,072.0	41,419.1	9,901.0	43,141.6	9,855.0	43,207.6	10,019.0	42,411.6	10,297.0	44,799.7	10,458.6	45,516.4	10,591.4	46,088.9
Total Labrador Combined Systems	17,006.1	73,330.4	15,677.0	68,936.5	15,398.0	66,976.3	15,826.0	66,178.5	15,594.0	68,694.7	15,851.0	69,126.0	15,784.0	68,272.3	16,062.0	71,060.8	16,513.4	72,355.0	16,696.2	73,135.5
Island Isolated Systems	2,090.3	7,515.9	2,006.4	6,798.8	1,717.1	5,929.9	1,836.0	5,512.3	2,001.0	5,944.3	1,810.0	6,226.4	1,844.0	6,087.6	1,897.0	6,149.6	1,873.0	6,030.9	1,869.1	6,019.3
Total Hydro Isolated Systems																				
Electricity Requirement	-	<u>80,846.3</u>	-	<u>75,735.4</u>	-	<u>72,906.2</u>	-	<u>71,690.8</u>	-	<u>74,639.0</u>	-	<u>75,352.4</u>	-	<u>74,359.9</u>	-	<u>77,210.3</u>	-	<u>78,385.9</u>	-	<u>79,154.7</u>

¹ Numbers may not add due to rounding.
² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.
³ The 2026 and 2027 Forecast is sourced to the June 2025 Rural Operating Load Forecast.
⁴ Peaks are non-coincident net annual maximums.
⁵ Net production excludes station services.

Newfoundland and Labrador Hydro
Schedule A-IV: Production Plan for 2027 Test Year (GWh)¹
Island Interconnected System

								Thermal	GT			Diesel		Purchases										
Month	System Load	BDE	HLK	USL	CAT	GCL	PRV	HRD	HWD	SVL	HRD	HRD	GNP	DLK Power Secondary	GF and BIF	Star Lake	Rattle Brook	Corner Brook CoGen	New World Dairy	St. Lawrence Wind	Fermeuse Wind	LIL	Total Power Purchases	Total Supplied
January	895.1	316.5	45.4	58.3	87.5	24.4	3.0	112.7	0.2	0.2	5.2	0.0	0.2	-	54.0	12.5	0.6	6.3	0.2	11.4	9.3	147.1	241.5	895.1
February	816.3	302.4	34.3	45.5	75.0	20.8	2.7	102.6	0.6	0.1	3.5	0.0	0.2	-	48.7	11.3	0.5	5.0	0.2	9.4	8.9	144.4	228.4	816.3
March	811.6	245.5	33.9	56.4	72.8	22.6	3.0	47.7	0.5	0.4	3.1	0.0	0.1	-	53.7	12.5	0.6	5.8	0.2	9.4	9.0	234.3	325.6	811.6
April	642.6	247.0	26.0	53.1	75.1	22.9	2.9	-	0.8	0.6	3.7	0.0	0.2	-	55.7	11.7	1.5	5.6	0.2	8.3	7.3	120.0	210.3	642.6
May	533.4	179.5	19.9	41.7	62.7	19.6	3.0	-	0.8	0.7	4.5	0.0	0.3	-	59.0	12.5	2.4	5.7	0.2	8.9	9.3	102.4	200.5	533.4
June	470.6	127.7	23.1	40.3	59.8	18.0	2.9	-	0.0	0.2	3.9	0.0	0.3	-	48.3	12.0	1.4	6.1	0.2	6.5	5.1	114.9	194.4	470.6
July	437.0	168.0	32.2	38.8	51.6	17.0	3.0	-	0.6	0.5	0.8	0.0	0.3	-	52.8	13.0	0.7	5.6	0.2	5.5	7.2	39.2	124.3	437.0
August	420.0	176.4	34.1	21.0	44.0	22.0	3.0	-	0.1	0.2	1.1	0.0	0.2	-	54.8	13.0	0.7	4.2	0.2	5.9	6.1	33.1	118.0	420.0
September	423.3	179.6	28.2	49.0	43.8	16.7	2.9	-	0.1	0.0	0.4	0.0	0.2	-	50.0	6.5	1.1	6.2	0.2	5.7	5.4	27.4	102.5	423.3
October	512.0	218.8	13.3	51.0	41.5	16.0	3.0	28.4	0.5	0.0	4.1	0.0	0.3	-	39.5	12.9	1.6	5.4	0.2	9.2	9.0	57.1	135.0	512.0
November	636.5	178.1	24.5	48.6	55.1	21.2	2.9	52.6	0.3	0.1	1.9	0.0	0.1	-	45.4	11.5	1.5	4.3	0.2	9.9	9.8	168.6	251.2	636.5
December	818.5	314.4	39.1	52.3	86.0	24.8	3.0	111.2	0.2	0.0	1.7	0.0	0.1	-	53.0	11.7	1.0	6.3	0.2	9.3	10.0	94.1	185.6	818.5
Total	7,416.9	2,654.0	354.0	556.0	755.0	246.0	35.0	455.2	4.7	3.1	33.9	0.1	2.5	-	614.9	141.1	13.8	66.5	2.8	99.4	96.3	1,282.6	2,317.4	7,416.9

¹ Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
Schedule A-V: Energy Supply and Fuel Expense for 2019–2027¹
Island Interconnected System

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast²	2026 Forecast	2027 Test Year
Total Energy Requirement (GWh)	7,202.4	7,238.0	6,663.5	6,524.3	6,579.5	6,870.6	6,858.4	7,117.7	7,482.5	7,416.9
Hydraulic Production (GWh)	4,600.5	4,524.6	4,507.9	4,495.0	4,643.6	4,390.7	4,400.8	4,357.5	4,600.0	4,600.0
Energy Receipts and Purchases (GWh) ³	1,508.8	1,452.9	1,169.2	1,302.3	1,194.9	1,817.9	1,792.0	2,082.3	2,302.2	2,317.4
Gas Turbine/Diesels Production (GWh) ⁴	23.3	3.9	(2.4)	16.5	(3.9)	13.4	(0.8)	13.5	41.4	44.3
Holyrood Production (GWh)	1,069.8	1,256.6	988.8	710.6	744.9	648.6	666.3	664.5	538.8	455.2
Holyrood No. 6 Fuel Conversion Factor (kWh/bbl)	583.0	588.0	586.0	568.0	573.0	540.0	558.0	N/A	583.0	563.0
Holyrood No. 6 Fuel Consumption (bbl)	1,834,980.0	2,135,751.0	1,687,513.0	1,252,542.7	1,300,093.3	1,201,828.7	1,193,645.0	1,147,058.0	924,234.0	808,571.0
No. 6 Fuel Production Cost (\$000)	194,686.0	196,567.9	142,929.0	98,070.5	163,464.2	149,914.6	140,702.5	117,589.4	71,042.5	65,010.0
No. 6 Fuel (\$/bbl) ⁵	106.10	92.04	84.70	78.30	125.73	124.74	117.88	102.51	76.87	80.40
Gas Turbine/Diesel Production Cost (\$000)	6,708.0	4,388.6	2,296.2	8,741.5	1,510.6	9,004.8	6,466.6	11,036.5	18,382.1	20,845.8

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Energy receipts and purchases reflect New World Dairy starting in 2019.

⁴ Standby generation operation includes operation to support system operations and maintenance requirements.

⁵ 2019 Test Year No. 6 Fuel price of \$105.9 excludes ignition costs, indirect costs and environmental handling fees, which are included in these calculations.

Schedule A-VI

Page 1 of 1

Newfoundland and Labrador Hydro
Schedule A-VI: Energy Purchases by Suppliers for 2019–2027¹
Island Interconnected System

Supplier	2019 Test Year		2019 Actuals		2020 Actuals		2021 Actuals		2022 Actuals		2023 Actuals		2024 Actuals		2025 Forecast ²		2026 Forecast		2027 Test Year	
	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000	GWh	\$000
Newfoundland Power at Hydro Request	-	-	0.1	17.0	0.1	-	0.2	112.0	-	-	0.1	42.0	0.0	-	0.1	134.0	-	-	-	-
CBPP Secondary ³	-	-	40.9	1,605.0	46.4	2,119.0	24.5	343.0	41.0	-	33.2	-	3.4	-	0.6	-	-	-	-	-
CBPP PPA ⁴	-	-	-	-	-	-	-	-	-	-	-	-	128.2	-	34.7	-	-	-	-	-
Star Lake	141.7	5,670.0	125.7	5,028.0	132.2	5,288.0	131.7	5,266.0	132.2	5,287.0	112.8	4,510.0	131.7	5,268.0	123.7	4,948.0	132.2	5,287.4	141.1	5,643.7
Rattle Brook	14.8	1,263.1	14.2	1,244.3	13.3	1,165.7	14.4	1,283.4	15.0	1,360.7	16.7	1,574.9	13.6	1,319.0	12.4	1,237.0	13.8	1,381.4	13.8	1,399.1
CBPP Co-Generation	66.5	12,534.3	55.2	10,428.7	50.4	9,542.7	50.1	9,488.2	46.1	8,738.2	51.2	7,264.1	22.1	1,867.0	48.8	3,728.0	66.5	5,145.0	66.5	4,594.8
St. Lawrence Wind	104.8	7,566.6	94.3	6,809.8	97.5	7,713.6	100.7	7,382.3	98.3	7,256.8	99.8	7,482.3	87.1	6,602.0	96.7	7,376.0	99.4	7,635.8	99.4	7,665.6
Fermeuse Wind	84.4	6,514.2	87.7	7,056.1	78.2	6,161.2	85.0	6,715.0	85.9	6,837.0	72.5	5,860.4	84.7	6,928.0	91.4	7,520.0	96.3	7,978.2	96.3	8,017.4
Exploits	615.0	24,599.9	574.0	22,958.8	568.6	22,746.0	581.3	23,252.4	584.6	23,384.2	632.1	25,262.9	578.8	23,151.0	558.3	22,332.0	614.9	24,594.7	614.9	24,594.7
New World Dairy	-	-	3.0	404.7	2.1	297.5	3.4	387.6	3.3	425.7	1.9	240.4	0.1	7.0	1.8	206.0	2.8	64.4	2.8	64.4
Muskrat Falls PPA ⁵	-	-	-	-	-	-	298.3	39,877.9	186.5	237,670.5	797.4	242,025.9	739.6	262,515.0	1,034.9	314,674.0	1,276.3	304,693.0	1,282.6	315,281.0
Transmission Funding Agreement	-	-	-	-	-	-	-	-	-	-	-	335,464.4	-	448,114.7	-	461,315.0	-	466,771.0	-	465,073.0
LIL	341.0	797.2	198.0	557.0	(11.2)	-	-	230.0	-	(0.1)	-	0.4	-	-	56.7	105.0	-	-	-	-
Maritime Link Imports	140.5	13,492.7	244.5	18,107.1	191.5	11,773.1	12.0	2,295.1	2.0	1.1	0.2	-	2.3	80.0	22.2	3,048.0	-	-	-	-
CBPP Firm Energy	-	-	15.4	1,323.0	-	-	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-
CBPP Capacity Assistance	-	2,992.0	-	2,793.0	-	2,900.0	-	3,416.0	-	2,565.0	-	2,898.0	0.5	7,067.0	-	7,541.0	-	7,549.7	-	7,700.7
Vale Capacity Assistance	-	213.0	-	264.9	-	212.8	-	159.6	-	210.7	-	-	-	190.4	-	48.0	-	190.4	-	190.4
Vale Capacity Assistance (Curtailable Load)	-	168.0	-	168.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Praxair Capacity Assistance	-	-	-	-	-	45.5	-	109.4	-	17.2	-	-	-	-	-	-	-	-	-	-
Total Power Purchases	1,508.8	75,810.9	1,452.9	78,765.3	1,169.2	69,965.0	1,302.3	100,317.9	1,194.9	293,753.9	1,817.9	632,625.7	1,792.0	763,109.1	2,082.3	834,212.0	2,302.2	831,290.9	2,317.4	840,224.7

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ CBPP Secondary amounts represent the actuals delivered to the Island Interconnected System. Starting in 2022, the amounts delivered were inadvertent.

⁴ Energy delivered to Hydro under the CBPP arrangement with Government at no cost to ratepayers.

⁵ Net energy delivered to the Island Interconnected System under the Muskrat Falls PPA.

Newfoundland and Labrador Hydro
Schedule A-VII: Fuel and Purchased Power Costs for 2019–2027
Isolated Systems
(\$000)

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast¹	2026 Forecast²	2027 Test Year²
Diesel Fuel ³	18,200.2	16,343.4	12,496.8	13,027.4	23,898.8	28,584.8	22,667.1	20,740.6	16,695.6	20,295.4
Purchased Power										
L'Anse-au-Loup ⁴	3,348.8	3,032.6	2,345.7	2,964.1	5,356.6	3,788.0	4,178.9	4,200.3	3,271.2	4,104.3
Ramea ⁵	164.0	98.1	76.5	59.5	140.6	138.5	63.5	39.5	144.8	177.1
Mary's Harbour	-	43.3	127.1	156.9	234.1	413.9	368.9	371.4	198.6	245.4
Total Purchased Power	3,512.8	3,174.0	2,549.3	3,180.5	5,731.3	4,340.4	4,611.3	4,611.2	3,614.6	4,526.8
Total Fuel and Purchased Power Costs	21,713.0	19,517.4	15,046.1	16,207.9	29,630.1	32,925.2	27,278.4	25,351.8	20,310.2	24,822.2

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Forecast dollars based on Hydro Rural Load Forecast, Spring 2025 and S&P Global Platts Commodity Insights May 2025.

³ L'Anse-au-Loup fuel purchases include deferred fuel savings.

⁴ Power purchases from Hydro-Québec are assumed to be available throughout the forecast period.

⁵ Ramea power purchases includes Frontier power purchases. It is assumed that wind generation will be available throughout the forecast period.

Schedule B



Newfoundland and Labrador Hydro
Schedule B-I: Total Operating Expenses by Cost Type
(\$000)¹

	2019 Test Year²	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast³	2026 Forecast	2027 Test Year
Labour										
Salaries	77,365	76,303	73,409	73,970	73,945	75,064	82,042	89,347	92,003	96,212
General Expenses Capitalized Deferral	-	-	-	-	-	-	-	(6,088)	(6,389)	(6,578)
Overtime	4,901	5,764	6,131	7,068	6,600	7,450	7,171	6,825	7,192	7,361
Other Labour-Related Costs	3,236	2,523	4,902	(2,038)	1,892	704	(723)	(1,898)	575	(574)
Total Labour	85,502	84,589	84,442	79,000	82,437	83,217	88,490	88,185	93,381	96,421
System Equipment and Maintenance	26,796	22,883	20,491	21,819	22,299	30,060	24,623	28,649	29,845	27,538
Other										
Office Supplies and Expenses	2,520	2,243	2,288	2,082	2,315	2,225	2,214	2,410	2,486	2,541
Professional Services	8,825	7,422	7,330	7,560	8,279	10,043	11,411	14,638	12,575	13,644
Insurance	3,425	3,507	3,785	4,412	4,703	4,973	4,885	4,709	4,670	4,624
Equipment Rentals	3,746	3,597	2,739	2,285	2,255	2,546	2,667	1,820	1,788	1,833
Travel	2,759	2,404	1,500	1,591	2,037	2,836	2,355	2,352	2,267	2,306
Miscellaneous Expenses	5,868	5,033	4,594	5,154	5,035	5,218	5,045	5,874	5,989	6,121
Building Rental and Maintenance	1,100	979	911	932	972	1,053	1,290	1,264	1,128	1,151
Transportation	1,274	1,359	1,215	1,863	2,358	2,446	2,368	1,841	2,793	2,993
Customer Costs	118	391	2,908	(703)	(511)	2,137	23	339	85	85
Total Other	29,635	26,935	27,270	25,175	27,443	33,477	32,258	35,247	33,780	35,297
Cost Allocations	(4,970)	(1,323)	1,337	243	(1,661)	(3,908)	(122)	(792)	(4,113)	(2,894)
Total Operating Expenses	136,963	133,083	133,540	126,237	130,518	142,847	145,249	151,288	152,893	156,362

¹ Numbers may not add due to rounding.

² The 2019 Test Year includes the settlement items and disallowance related to the 2017 GRA of \$8.4 million, as well as the current departmental groupings that were changed after the 2017 GRA filing.

³ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

Newfoundland and Labrador Hydro
Schedule B-II: Total Operating Expenses by Functional Area
(\$'000)¹

	2019 Test Year ²	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ³	2026 Forecast	2027 Test Year
Operations										
Transmission and Distribution	41,658	41,669	36,580	36,888	38,746	40,901	39,329	41,845	44,006	45,138
Production	43,742	39,314	36,525	38,838	37,128	40,164	40,947	42,058	43,477	44,565
Engineering Services	5,982	3,957	5,279	4,436	4,477	4,396	5,581	5,030	5,080	5,107
System Planning	1,673	1,867	2,290	2,206	2,893	3,443	3,757	5,441	4,289	4,321
Newfoundland and Labrador System Operator	3,145	4,472	4,309	4,429	4,397	4,221	4,893	5,212	5,521	5,661
Asset Management	637	824	1,560	1,290	1,707	1,627	1,599	1,673	2,346	2,420
Major Projects	-	-	-	-	-	26	739	305	32	40
Operations Technology	11,240	8,812	10,046	10,023	10,608	11,961	13,507	14,013	14,776	14,079
Total Operations	108,077	100,915	96,591	98,110	99,955	106,740	110,352	115,577	119,527	121,330
General and Administration										
Executive	2,859	2,963	5,646	642	4,066	4,396	2,661	3,292	2,605	2,689
Financial Services and Other	10,051	9,376	10,621	11,459	9,915	12,045	12,323	11,228	9,454	9,153
People, Culture and Corporate Affairs	10,126	9,344	8,151	8,154	8,725	8,530	9,686	10,848	10,932	11,529
Regulatory, Customer Service and Energy Optimization	11,178	10,486	12,531	7,872	7,857	11,135	10,228	10,344	10,374	11,661
Total General and Administration	34,215	32,169	36,949	28,127	30,563	36,107	34,898	35,712	33,366	35,031
GRA Order Vacancy Allowance ⁴	(1,328)	-	-	-	-	-	-	-	-	-
GRA Order Productivity Allowance ⁵	(4,000)	-	-	-	-	-	-	-	-	-
Total Operating Expenses	136,964	133,083	133,540	126,237	130,518	142,847	145,249	151,289	152,893	156,362

¹ Numbers may not add due to rounding.

² The 2019 Test Year includes the settlement items and disallowance related to the 2017 GRA of \$8.4 million, as well as the current departmental groupings that were changed after the 2017 GRA filing.

³ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

⁴ Hydro did not allocate the vacancy allowance noted in Board Order No. P.U. 16(2019) by functional department.

⁵ Hydro did not allocate the productivity allowance noted in Board Order No. P.U. 16(2019) by functional department.

Newfoundland and Labrador Hydro
 Schedule B-III: Operating Expenses – Cost Allocation (Recoveries)
 (\$000)¹

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ²	2026 Forecast	2027 Test Year
Net Administrative Fees	2,787	1,943	3,403	4,061	1,958	4,104	5,216	6,502	6,056	4,705
Productivity Allowance	(5,102)	-	-	-	-	-	-	-	(4,000)	(4,000)
CDM Program Deferral	(2,100)	(1,507)	(555)	(1,136)	(1,081)	(1,384)	(1,384)	(1,781)	(1,892)	(1,853)
External Cost Recoveries	(481)	(887)	(926)	(692)	(1,543)	(1,410)	(1,954)	(2,262)	(297)	(320)
Removal and Decommissioning Recovery	-	-	-	(276)	(603)	(4,794)	(1,666)	(2,822)	(3,465)	(965)
Other Cost Recoveries	(73)	(873)	(584)	(1,714)	(393)	(423)	(333)	(429)	(515)	(461)
Total Cost Allocation (Recoveries)	(4,970)	(1,323)	1,337	243	(1,661)	(3,908)	(122)	(792)	(4,113)	(2,894)

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

Schedule C



Newfoundland and Labrador Hydro
Schedule C-I: Total Muskrat Falls PPA and Transmission Funding Agreement Supply Costs
(\$ Millions)

	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Actual	Forecast¹	Forecast	Test Year
Muskrat Falls PPA ²	92.8	214.8	216.9	273.3	323.0	323.6	323.9
Transmission Funding Agreement ³	-	-	335.5	448.1	461.3	466.8	465.1
Subtotal per Agreements	92.8	214.8	552.4	721.4	784.3	790.4	789.0
Muskrat Falls PPA Sustaining Capital Deferral ⁴	-	(0.5)	(4.4)	(10.8)	(8.4)	(18.9)	(8.6)
Total Supply Costs	92.8	214.3	548.0	710.6	775.9	771.5	780.4

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Please refer to Schedule C-III.

³ Please refer to Schedule C-V.

⁴ Includes Muskrat Falls Sustaining Capital Costs from Schedule C-III and Labrador Transmission Assets Sustaining Capital Costs from Schedule C-IV.

Newfoundland and Labrador Hydro
Schedule C-II: Monetized NLH Deferred Energy
(\$ Millions)

	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Actual	Forecast¹	Forecast	Test Year
Monetized NLH Deferred Energy	-	25.4	13.3	73.8	46.0	29.6	38.1

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

Newfoundland and Labrador Hydro
Schedule C-III: Muskrat Falls PPA Supply Costs
 (\$ Millions)¹

	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Actual	Forecast²	Forecast	Test Year
Base Block Capital Cost Recovery³	72.7	143.6	140.7	177.9	191.1	204.9	216.1
Other Costs							
Operating Costs	2.9	20.9	22.2	26.8	28.4	24.6	21.7
Impact and Benefit Agreement	0.6	7.0	5.9	5.9	43.3	13.9	14.2
Water Power Rental	0.9	14.3	12.2	15.5	14.4	16.1	16.4
Other	0.3	0.1	(0.5)	(1.1)	(3.3)	0.7	0.7
Muskrat Falls Sustaining Capital Costs	-	-	0.4	0.3	4.4	3.7	5.4
Labrador Transmission Assets Payments ⁴	15.4	28.9	36.0	48.0	44.7	59.7	49.4
Total Other Costs	20.1	71.2	76.2	95.4	131.9	118.7	107.8
Muskrat Falls PPA Supply Costs per Agreement	92.8	214.8	216.9	273.3	323.0	323.6	323.9
Muskrat Falls PPA Sustaining Capital Deferral ⁵	-	(0.5)	(4.4)	(10.8)	(8.4)	(18.9)	(8.6)
Total Muskrat Falls PPA Supply Costs	92.8	214.3	212.5	262.5	314.6	304.7	315.3

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Includes Base Block Capital Cost Recovery Adjustment in 2021–2023.

⁴ Please refer to Schedule C-IV.

⁵ Includes Muskrat Falls Sustaining Capital Costs and Labrador Transmission Assets Sustaining Capital Costs from Schedule C-IV.

Newfoundland and Labrador Hydro
Schedule C-IV: Labrador Transmission Assets Payments Under the Muskrat Falls PPA
(\$ Millions)

	2021	2022	2023	2024	2025	2026	2027
	Actual	Actual	Actual	Actual	Forecast¹	Forecast	Test Year
Labrador Transmission Assets Capital Cost Recovery²	14.5	24.0	27.4	32.7	35.2	37.7	39.7
Other Costs							
Operating Costs	0.9	4.4	4.6	4.9	5.5	6.6	6.3
Labrador Transmission Assets Sustaining Capital Costs	-	0.5	3.9	10.5	4.0	15.3	3.2
Other	-	-	0.1	(0.1)	-	0.1	0.2
Total Other Costs	0.9	4.9	8.6	15.3	9.5	22.0	9.7
Total Labrador Transmission Assets Payments	15.4	28.9	36.0	48.0	44.7	59.7	49.4

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Includes Capital Cost Recovery Adjustment in 2021–2023.

Newfoundland and Labrador Hydro
Schedule C-V: Transmission Funding Agreement Supply Costs
(\$ Millions)

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ¹	2026 Forecast	2027 Test Year
Rent							
Return On Equity	-	-	146.4	207.3	209.0	208.4	207.5
Interest	-	-	84.1	94.6	102.8	104.3	103.6
Depreciation	-	-	81.2	113.5	114.3	114.9	115.2
Other	-	-	0.7	1.6	1.5	1.3	1.2
Total Rent	-	-	312.4	417.0	427.6	428.9	427.5
Operating Costs	-	-	23.1	31.1	33.7	37.9	37.6
Fixed Payment of \$30,000 ²	-	-	-	-	-	-	-
Total Transmission Funding Agreement Supply Costs	-	-	335.5	448.1	461.3	466.8	465.1

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Fixed payment of \$30,000 is included in the total; however, it does not show in the schedule due to rounding.

Schedule D



Newfoundland and Labrador Hydro
Schedule D-I: Revenue Requirement Analysis
(\$000s)¹

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ²	2026 Forecast	2027 Test Year	Variance from 2019 Test Year to 2027 Test Year
Revenue Requirement											
Energy Sales	589,829	599,986	573,797	565,082	637,319	640,197	640,615	641,190	648,509	730,003	140,174
Revenue Deficiency	51,813	52,568	-	-	-	-	-	-	-	66,189	14,376
Generation Demand Cost Recovery	1,399	1,321	1,463	1,476	1,491	1,459	1,560	1,560	1,560	1,522	122
Total Revenue Requirement	643,041	653,875	575,260	566,558	638,811	641,656	642,175	642,749	650,069	797,713	154,672
Expenses											
Operating Costs	136,964	133,083	133,540	126,237	130,518	142,847	145,249	151,289	152,893	156,362	19,398
Fuels	219,857	223,928	159,932	171,857	242,958	245,088	244,682	236,963	231,555	106,311	(113,546)
Muskrat Falls Supply Costs	-	-	-	-	-	-	-	-	-	780,354	780,354
Power Purchases	81,662	84,944	76,118	65,913	64,715	61,643	59,370	64,938	65,933	66,921	(14,741)
Depreciation	85,429	87,569	84,403	88,548	85,611	88,067	90,208	94,115	103,630	116,568	31,139
Accretion of Asset Retirement Obligation	364	338	289	77	186	737	1,023	1,081	1,093	1,097	733
Other Income and Expense	-	4,915	382	645	2,084	(99)	475	18	-	-	-
	524,276	534,777	454,664	453,277	526,072	538,282	541,007	548,405	555,104	1,227,613	703,337
Other Adjustments											
CIAC Revenue	(1,815)	(1,845)	(1,953)	(2,237)	(2,230)	(2,166)	(2,279)	(2,308)	(2,325)	(2,347)	(532)
Other Revenue	(2,109)	(2,293)	(2,849)	(9,178)	(9,755)	(11,006)	(4,236)	(5,392)	(2,153)	(3,403)	(1,294)
Transmission Tariff Revenue	-	-	(121)	(1,242)	-	-	-	10	-	(18,338)	(18,338)
Net Export Revenue	-	-	-	-	-	-	-	-	-	(40,178)	(40,178)
Cost of Service Exclusions ³	(3,088)	(5,908)	(963)	(782)	(896)	(368)	(404)	(402)	(402)	(397)	2,691
Compliance Adjustments	-	6,779	-	-	-	-	-	-	-	-	-
	(7,012)	(3,267)	(5,886)	(13,439)	(12,880)	(13,541)	(6,918)	(8,092)	(4,880)	(64,662)	(57,651)
Rate Mitigation	-	-	-	-	-	-	-	-	-	(501,964)	(501,964)
	517,264	531,511	448,778	439,838	513,192	524,741	534,088	540,312	550,224	660,987	143,722
Return on Rate Base⁴	125,777	122,364	126,482	126,720	125,619	116,915	108,086	102,437	99,845	136,727	10,950
Average Rate Base⁴	2,317,269	2,306,047	2,310,559	2,321,756	2,325,085	2,329,352	2,379,043	2,500,008	2,604,025	2,802,095	
Rate of Return on Rate Base^{4,5}	5.43%	5.31%	5.47%	5.46%	5.40%	5.02%	4.54%	4.10%	3.83%	4.88%	

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Depreciation on assets excluded from rate base. 2019 also includes the disallowance of the depreciation of the CBPP frequency converter.

⁴ Please refer to Schedule D-II, p. 4.

⁵ Approved rate of return from Hydro's 2017 GRA was 5.43%; however, this was subsequently updated to 5.45% effective July 1, 2025, in accordance with Board Order No. P.U. 10(2025).

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Statement of Income and Retained Earnings
(\$000s)

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast¹	2026 Forecast	2027 Test Year
Revenue										
Energy Sales	589,829	599,986	573,797	565,082	637,319	640,197	640,615	641,190	648,509	730,003
Export Revenue	-	-	-	-	-	-	-	-	-	64,818
Transmission Tariff Revenue	-	-	121	1,242	-	-	-	(10)	-	18,338
Rate Mitigation	-	-	-	-	-	-	-	-	-	501,964
Revenue Deficiency	51,813	52,568	-	-	-	-	-	-	-	66,189
Generation Demand Cost Recovery	1,399	1,321	1,463	1,476	1,491	1,459	1,560	1,560	1,560	1,522
CIAC Revenue	1,815	1,845	1,953	2,237	2,230	2,166	2,279	2,308	2,325	2,347
Other Revenue	2,109	2,293	2,849	9,178	9,755	11,006	4,236	5,392	2,153	3,403
Total Revenue	646,965	658,013	580,183	579,215	650,795	654,828	648,689	650,440	654,547	1,388,583
Expenses										
Operating Costs	136,964	133,083	133,540	126,237	130,518	142,847	145,249	151,289	152,893	156,362
Other Income and Expense	-	4,915	382	645	2,084	(99)	475	18	-	-
Amortization of Foreign Exchange Losses	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157
Fuels	219,857	223,928	159,932	171,857	242,958	245,088	244,682	236,963	231,555	106,311
Power Purchases ²	81,662	84,944	76,118	65,913	64,715	61,643	59,370	64,938	65,933	847,275
Power Purchases - Export Costs ³	-	-	-	-	-	-	-	-	-	24,640
Depreciation	85,429	87,569	84,403	88,548	85,611	88,067	90,208	94,115	103,630	116,568
Accretion of Asset Retirement Obligation	364	338	289	77	186	737	1,023	1,081	1,093	1,097
Interest ⁴	93,057	91,876	87,334	87,982	86,253	82,405	85,032	87,464	84,156	79,137
Total Expenses	619,490	628,810	544,154	543,416	614,482	622,844	628,195	638,026	641,417	1,333,547
Net Income (Loss)	27,475	29,202	36,029	35,799	36,313	31,984	20,494	12,414	13,130	55,035
Retained Earnings										
Balance - Beginning of Year	323,017	310,578	339,780	375,809	411,608	447,921	479,905	500,399	513,650	526,780
Opening Adjustment - Retained Earnings ⁵	-	-	-	-	-	-	-	837	-	-
Dividends	-	-	-	-	-	-	-	-	-	-
Balance - End of Year	350,492	339,780	375,809	411,608	447,921	479,905	500,399	513,650	526,780	581,816

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Power Purchases include Muskrat Falls supply costs and power purchases from Schedule D-I.

³ Power Purchases - Export Costs are grouped within Net Export Revenue in Schedule D-I.

⁴ Please refer to Schedule D-II, p. 6.

⁵ For the purpose of the capital forecast, Hydro is using its assumptions from its 2025 capital budget, which is comprised of 2024 forecast information. This adjustment represents the difference between that forecast and 2025 actual results.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Balance Sheet
(\$000s)

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast¹	2026 Forecast	2027 Test Year
Assets										
Current Assets										
Cash and Cash Equivalents	-	7,641	27,755	41,785	16,267	29,350	3,150	-	-	-
Accounts Receivable	87,089	109,519	79,739	107,673	97,304	117,555	127,073	88,346	91,427	118,725
Inventory	79,683	103,248	92,344	84,154	98,992	100,706	103,747	110,175	115,468	119,268
Prepaid Expenses	4,081	5,299	6,087	6,164	5,707	4,678	4,189	4,182	4,120	4,176
Due from Related Parties	-	881	2,724	55,669	32,257	1,242	1,425	-	-	-
	<u>170,853</u>	<u>226,588</u>	<u>208,649</u>	<u>295,445</u>	<u>250,527</u>	<u>253,531</u>	<u>239,584</u>	<u>202,703</u>	<u>211,015</u>	<u>242,169</u>
Property, Plant, and Equipment	2,247,302	2,204,095	2,211,150	2,231,345	2,251,312	2,333,924	2,409,910	2,582,008	2,775,624	3,194,229
Right of Use Assets	-	2,313	2,424	2,480	2,452	2,423	2,397	2,397	2,397	2,397
Sinking Funds	223,976	173,965	182,570	191,721	201,930	205,865	211,246	233,559	66,506	86,159
Regulatory Assets	168,015	112,199	159,184	164,455	504,348	849,682	1,447,232	1,641,032	1,797,164	2,084,666
Total Assets	<u>2,810,146</u>	<u>2,719,160</u>	<u>2,763,977</u>	<u>2,885,446</u>	<u>3,210,569</u>	<u>3,645,425</u>	<u>4,310,369</u>	<u>4,661,699</u>	<u>4,852,706</u>	<u>5,609,620</u>
Liabilities and Shareholder Equity										
Current Liabilities										
Promissory Notes	291,930	233,000	262,000	55,000	131,000	230,000	590,000	279,853	245,261	215,969
Accounts Payable and Accrued Liabilities	67,375	106,860	84,250	89,214	99,019	113,067	114,110	32,620	33,992	58,157
Accrued Interest	19,949	24,946	24,946	25,339	25,363	25,362	25,363	27,662	23,161	29,317
Deferred Credits	370	647	813	2,532	3,011	3,656	7,549	8,332	8,332	8,332
Due to (from) Related Parties	3,780	2,750	2,577	2,532	17,914	-	18,447	20,619	20,619	20,619
Promissory Notes - Non-regulated	(11,067)	(22,052)	(15,576)	(14,812)	(2,711)	13,490	2,775	-	-	-
	<u>372,337</u>	<u>346,151</u>	<u>359,010</u>	<u>159,805</u>	<u>273,595</u>	<u>385,575</u>	<u>758,244</u>	<u>369,086</u>	<u>331,365</u>	<u>332,394</u>
Deferred Capital Contribution	51,364	51,543	52,635	56,073	64,706	66,236	69,350	68,455	67,192	66,650
Long-Term Payable	-	487	824	824	166,290	452,120	726,659	1,154,385	1,469,560	1,767,103
Long-Term Debt	1,794,947	1,782,533	1,772,001	2,048,049	2,039,320	2,023,540	2,008,430	2,306,930	2,207,886	2,608,723
Lease Liability	-	2,342	2,512	2,591	2,604	2,611	2,623	2,623	2,623	2,623
Regulatory Liabilities	5,348	2,000	1,726	3,223	6,579	16,615	21,220	15,697	12,949	11,455
Asset Retirement Obligations	14,630	14,459	15,129	14,835	17,200	26,728	28,649	33,846	33,960	34,754
Employee Future Benefits	91,356	96,907	102,594	93,998	67,581	78,452	84,816	92,565	96,405	100,438
Contributed Capital	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Retained Earnings	350,492	339,780	375,809	411,607	447,920	479,905	500,398	513,650	526,780	581,816
Accumulated Other Comprehensive Income	29,672	(17,042)	(18,262)	(5,559)	24,773	13,643	9,980	4,463	3,987	3,665
Total Liabilities and Shareholders' Equity	<u>2,810,146</u>	<u>2,719,160</u>	<u>2,763,978</u>	<u>2,885,446</u>	<u>3,210,569</u>	<u>3,645,425</u>	<u>4,310,369</u>	<u>4,661,700</u>	<u>4,852,707</u>	<u>5,609,621</u>

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Capital Structure
(\$000s)¹

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast²	2026 Forecast	2027 Test Year
Regulated Capital Structure										
Long-Term Debt	1,794,947	1,782,533	1,772,001	2,048,049	2,039,320	2,023,540	2,008,430	2,306,930	2,207,886	2,608,723
Promissory Notes	291,930	233,000	262,000	55,000	131,000	230,000	590,000	279,853	245,261	215,969
Sinking Funds	(183,238)	(173,965)	(182,570)	(191,721)	(201,930)	(205,865)	(211,246)	(233,559)	(66,506)	(86,159)
	<u>1,903,639</u>	<u>1,841,568</u>	<u>1,851,431</u>	<u>1,911,328</u>	<u>1,968,390</u>	<u>2,047,675</u>	<u>2,387,184</u>	<u>2,353,224</u>	<u>2,386,641</u>	<u>2,738,533</u>
Cost of Service Exclusions	-	-	-	-	-	-	-	-	-	-
Non-Regulated Debt Pool	(11,067)	(22,052)	(15,576)	(14,812)	(2,711)	13,490	2,775	-	-	-
Net Regulated Debt	<u>1,892,572</u>	<u>1,819,516</u>	<u>1,835,855</u>	<u>1,896,516</u>	<u>1,965,679</u>	<u>2,061,165</u>	<u>2,389,959</u>	<u>2,353,224</u>	<u>2,386,641</u>	<u>2,738,533</u>
Funded Asset Retirement Obligation ³	14,443	14,366	14,276	14,396	14,344	15,369	18,141	20,175	23,397	27,299
Employee Future Benefits ⁴	76,085	79,680	83,790	87,830	91,509	91,513	94,773	97,479	101,171	105,102
Contributed Capital	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Retained Earnings Cost of Service Exclusions	33,484	35,802	43,113	50,221	57,840	64,970	72,198	79,448	88,103	97,292
Retained Earnings	350,492	339,780	375,809	411,607	447,920	479,905	500,398	513,650	526,780	581,816
Total	<u>2,467,076</u>	<u>2,389,144</u>	<u>2,452,842</u>	<u>2,560,570</u>	<u>2,677,293</u>	<u>2,812,922</u>	<u>3,175,469</u>	<u>3,163,976</u>	<u>3,226,092</u>	<u>3,650,041</u>
Regulated Capital Structure (%)										
Debt	76.7%	76.2%	74.8%	74.1%	73.4%	73.3%	75.3%	74.4%	74.0%	75.0%
Asset Retirement Obligation	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.6%	0.6%	0.7%	0.7%
Employee Future Benefits	3.1%	3.3%	3.4%	3.4%	3.4%	3.3%	3.0%	3.1%	3.1%	2.9%
Equity	19.6%	19.9%	21.2%	21.9%	22.6%	22.9%	21.2%	21.9%	22.2%	21.3%
Total	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>
Regulated Average Capital Structure (%)										
Debt	76.80%	76.84%	75.78%	74.46%	73.74%	73.35%	74.27%	74.82%	74.18%	74.50%
Asset Retirement Obligation	0.61%	0.61%	0.58%	0.57%	0.55%	0.54%	0.56%	0.60%	0.68%	0.74%
Employee Future Benefits	3.12%	3.26%	3.25%	3.42%	3.42%	3.34%	3.12%	3.03%	3.11%	3.01%
Equity	19.48%	19.29%	20.39%	21.55%	22.28%	22.78%	22.05%	21.54%	22.03%	21.75%
Total	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>
Weighted Average Cost of Capital (WACC)										
Embedded Cost of Debt	4.91%	4.87%	4.74%	4.75%	4.66%	4.52%	4.75%	4.28%	4.02%	4.05%
Asset Retirement Obligation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Employee Future Benefits	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Equity	8.50%	8.80%	8.50%	8.50%	8.50%	8.50%	8.50%	8.60%	8.60%	8.60%
WACC	<u>5.43%</u>	<u>5.44%</u>	<u>5.32%</u>	<u>5.37%</u>	<u>5.33%</u>	<u>5.25%</u>	<u>5.40%</u>	<u>5.06%</u>	<u>4.88%</u>	<u>4.88%</u>

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Please refer to Schedule D-II, p. 7.

⁴ Please refer to Schedule D-II, p. 5.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Rate of Return on Rate Base
(\$000s)

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ¹	2026 Forecast	2027 Test Year
Property, Plant, and Equipment	2,240,847	2,198,146	2,209,194	2,226,877	2,237,594	2,317,579	2,407,226	2,578,440	2,772,123	3,190,731
Add: Accumulated Depreciation (Net of Disposal and Removal Pools)	446,385	449,739	523,797	598,649	654,859	713,347	773,107	853,984	971,755	1,071,824
Less: Work in Progress ²	(12,512)	(37,417)	(24,988)	(9,164)	(22,755)	(59,596)	(62,088)	(112,989)	(272,316)	(619,405)
Capital Assets in Service	2,674,720	2,610,468	2,708,003	2,816,362	2,869,698	2,971,330	3,118,245	3,319,435	3,471,562	3,643,150
Less: Asset Retirement Obligation	(124)	(67)	(768)	(352)	(2,734)	(11,237)	(10,385)	(13,554)	(10,446)	(7,338)
Add: CIAC ¹	(44,965)	(45,593)	(50,680)	(51,605)	(50,987)	(49,857)	(66,689)	(64,887)	(63,691)	(63,150)
Less: Accumulated Depreciation	(446,385)	(449,739)	(523,797)	(598,649)	(654,859)	(713,347)	(773,107)	(853,984)	(971,755)	(1,071,824)
Capital Assets - Current Year	2,183,246	2,115,068	2,132,758	2,165,756	2,161,118	2,196,889	2,268,064	2,387,010	2,425,670	2,500,838
Capital Assets - Previous Year	2,083,554	2,083,539	2,115,068	2,132,758	2,165,756	2,161,118	2,196,889	2,268,064	2,387,010	2,425,670
Unadjusted Capital Assets - Average	2,133,400	2,099,304	2,123,913	2,149,257	2,163,437	2,179,004	2,232,477	2,327,537	2,406,340	2,463,254
Less: Average Net Assets Excluded from Rate Base	(11,519)	(9,679)	(8,257)	(8,154)	(8,628)	(7,811)	(7,713)	(7,000)	(6,598)	(6,199)
Capital Assets - Average	2,121,881	2,089,625	2,115,656	2,141,103	2,154,809	2,171,193	2,224,764	2,320,537	2,399,742	2,457,055
Working Capital Allowance - Other	2,022	1,299	1,409	122	1,276	702	1,416	1,314	732	1,562
Working Capital Allowance - Muskrat Falls Related	-	-	-	-	-	-	-	-	-	115,124
Fuel	57,150	57,611	54,075	55,803	70,512	57,802	53,950	60,946	65,404	68,029
Materials and Supplies	32,884	37,701	38,438	38,326	38,856	41,349	43,698	44,949	44,837	44,722
Deferred Charges ³	103,333	119,811	100,981	86,402	59,632	58,306	55,215	72,262	93,310	115,602
Average Rate Base	2,317,269	2,306,047	2,310,559	2,321,756	2,325,085	2,329,352	2,379,043	2,500,008	2,604,025	2,802,095
Net Income	27,475	29,202	36,029	35,799	36,313	31,984	20,494	12,414	13,130	55,035
Add: Cost of Service Exclusions										
Depreciation on Assets Excluded from Rate Base	3,088	1,741	963	782	896	368	404	402	402	397
Interest Cost of Service Exclusions ⁴	6,302	6,348	6,348	6,326	6,724	6,761	6,824	6,848	8,253	8,792
Other Cost of Service Exclusions		4,167								
Compliance Adjustment		(6,779)								
Regulated Interest ⁵	88,912	87,685	83,143	83,813	81,686	77,801	80,365	82,773	78,060	72,502
Return on Rate Base	125,777	122,364	126,483	126,720	125,619	116,914	108,087	102,437	99,845	136,727
Rate of Return on Rate Base	5.43%	5.31%	5.47%	5.46%	5.40%	5.02%	4.54%	4.10%	3.83%	4.88%

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Contributions for assets that are in work in progress have been included in work in progress.

³ Please refer to Schedule D-V.

⁴ Interest cost of service exclusions primarily relate to the disallowed portion of the debt guarantee fee.

⁵ Please refer to Schedule D-II, p. 6.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Employee Future Benefits
(\$000s)

	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ¹	2026 Forecast	2027 Test Year
Accrued Employee Future Benefits Liability										
Balance - Beginning of Year	72,778	73,770	79,680	83,790	87,830	91,509	91,513	94,773	97,479	101,171
Current Service	3,159	3,365	3,856	3,974	3,333	1,743	2,016	2,274	2,486	2,603
Interest	3,493	3,405	3,174	2,834	3,213	3,526	3,676	4,024	4,396	4,579
Amortization of Actuarial Losses	33	-	109	186	-	(2,033)	(996)	(653)	(148)	(102)
Amortization of Past Service Costs	20	20	20	-	-	-	-	-	-	-
Past Service Cost	-	2,233	-	-	-	-	-	-	-	-
Transfers	-	-	78	282	(44)	(196)	1,403	-	-	-
Benefits Paid	(3,398)	(3,113)	(3,127)	(3,236)	(2,823)	(3,036)	(2,839)	(2,939)	(3,042)	(3,149)
Funded Employee Future Benefits²	76,085	79,680	83,790	87,830	91,509	91,513	94,773	97,479	101,171	105,102
Opening Adjustment - Other Comprehensive Income (OCI)	1,349	1,349	1,349	1,349	1,349	1,349	1,349	1,349	1,349	1,349
Actuarial Losses Amortized through OCI	4,692	4,692	4,692	4,692	4,692	4,692	4,692	4,692	4,692	4,692
Unamortized Losses	9,230	11,186	12,753	89	(30,018)	(19,207)	(15,847)	(10,804)	(10,656)	(10,554)
Transfers	-	-	10	38	49	105	(151)	(151)	(151)	(151)
Accrued Employee Future Benefits Obligation³	91,356	96,907	102,594	93,998	67,581	78,452	84,816	92,565	96,405	100,438

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Please refer to Schedule D-II, p. 3.

³ Please refer to Schedule D-II, p. 2.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts

Interest
(\$000s)

	2019	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Test Year	Actual	Actual	Actual	Actual	Actual	Actual	Forecast¹	Forecast	Test Year
Interest										
Long-Term Debt	92,475	92,475	92,475	96,220	97,749	97,725	97,725	100,025	94,425	101,992
Accretion of Long-Term Debt	(170)	(170)	(156)	885	1,339	1,394	1,454	1,521	956	836
Amortization of Foreign Exchange Losses	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157
Debt Guarantee Fee	8,513	8,605	8,624	8,602	8,703	8,794	8,940	9,008	10,327	10,571
Interest Cost of Service Exclusions ²	(6,302)	(6,348)	(6,348)	(6,326)	(6,724)	(6,761)	(6,824)	(6,848)	(8,253)	(8,792)
Other Interest	4,993	2,853	1,936	(83)	398	2,173	17,565	11,293	3,968	4,785
Interest on Sinking Fund	(11,484)	(11,386)	(12,132)	(12,895)	(13,626)	(14,449)	(15,285)	(15,663)	(8,249)	(7,902)
Finance Charges³	90,182	88,186	86,556	88,560	89,996	91,033	105,732	101,493	95,331	103,647
Interest on Rate Stabilization Plan	813	1,488	(1,897)	(3,200)	(2,803)	(2,990)	(2,224)	(1,241)	(292)	(25)
Interest on Supply Cost Variance Deferral Account	-	-	-	9	(4,603)	(8,320)	(21,008)	(12,536)	(6,048)	(8,277)
Interest on Electrification Cost Deferral	-	-	-	-	-	-	-	(46)	(52)	(52)
Lower Churchill Project Sustaining Capital Interest During Construction	-	-	-	-	(22)	(68)	(183)	(160)	(899)	(411)
Interest Capitalized During Construction ⁴	(2,083)	(1,989)	(1,516)	(1,556)	(882)	(1,854)	(1,952)	(4,737)	(9,980)	(22,380)
Regulated Interest	88,912	87,685	83,143	83,813	81,686	77,801	80,365	82,773	78,060	72,502
Amortization of Foreign Exchange Losses	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)
Debt Guarantee Fee Exclusion	6,302	6,348	6,348	6,326	6,724	6,761	6,824	6,848	8,253	8,792
Interest⁵	93,057	91,876	87,334	87,982	86,253	82,405	85,032	87,464	84,156	79,137

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Interest cost of service exclusions primarily relate to the disallowed portion of the debt guarantee fee.

³ Please refer to Schedule D-IV.

⁴ Interest Capitalized During Construction in 2026 Forecast and 2027 Test Year assumes Board approval of Hydro's Allowance for Funds Used During Construction Deferral account.

⁵ Please refer to Schedule D-II, p. 1.

Newfoundland and Labrador Hydro
Schedule D-II: Financial Results and Forecasts
Funded Asset Retirement Obligation
(\$000s)¹

	2019	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Test Year	Actual	Actual	Actual	Actual	Actual	Actual	Forecast²	Forecast	Test Year
Funded Asset Retirement Obligation										
Balance - Beginning of Year	14,082	14,503	14,366	14,276	14,396	14,344	15,369	18,141	20,175	23,397
Accretion	364	338	289	77	186	737	1,023	1,081	1,093	1,097
Depreciation	(345)	(379)	(170)	95	(121)	355	1,726	2,478	3,108	3,108
Asset Retirement Obligation Disposed	(118)	(96)	(210)	(52)	(117)	(67)	23	(1,525)	(979)	(303)
Compliance Adjustment	460	-	-	-	-	-	-	-	-	-
Balance - End of Year³	14,443	14,366	14,276	14,396	14,344	15,369	18,141	20,175	23,397	27,299

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Please refer to Schedule D-II, p. 3.

Newfoundland and Labrador Hydro
Schedule D-III: Return on Rate Base (Existing Rates)
(\$000s)¹

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ²	2026 Existing Rates	2027 Existing Rates
Revenue									
Energy Sales	599,986	573,797	565,082	637,319	640,197	640,615	641,190	648,509	649,505
Transmission Tariff Revenue	-	121	1,242	-	-	-	(10)	-	-
Revenue Deficiency	52,568								
Generation Demand Cost Recovery	1,321	1,463	1,476	1,491	1,459	1,560	1,560	1,560	1,560
CIAC Revenue	1,845	1,953	2,237	2,230	2,166	2,279	2,308	2,325	2,350
Other Revenue	2,293	2,849	9,178	9,755	11,006	4,236	5,392	2,153	2,153
Total Revenue	658,013	580,183	579,215	650,795	654,828	648,689	650,440	654,547	655,568
Expenses									
Operating Costs	133,083	133,540	126,237	130,518	142,847	145,249	151,289	152,893	150,572
Other Income and Expense	4,915	382	645	2,084	(99)	475	18	-	-
Amortization of Foreign Exchange Losses	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157
Fuels	223,928	159,932	171,857	242,958	245,088	244,682	236,963	231,555	232,177
Power purchases	84,944	76,118	65,913	64,715	61,643	59,370	64,938	65,933	66,922
Depreciation	87,569	84,403	88,548	85,611	88,067	90,208	94,115	103,630	113,392
Accretion of Asset Retirement Obligation	338	289	77	186	737	1,023	1,081	1,093	1,097
Interest	91,876	87,334	87,982	86,253	82,405	85,032	87,464	84,156	80,644
Total Expenses	628,810	544,154	543,416	614,482	622,844	628,195	638,026	641,417	646,961
Net Income (Loss)	29,202	36,029	35,799	36,313	31,984	20,494	12,414	13,130	8,607
Unadjusted Return on Regulated Equity	29,202	36,029	35,799	36,313	31,984	20,494	12,414	13,130	8,607
Add: Cost of Service Exclusions									
Depreciation on Assets Excluded from Rate Base	1,741	963	782	896	368	404	402	402	402
Interest Cost of Service Exclusions ³	6,348	6,348	6,326	6,724	6,761	6,824	6,848	8,253	8,792
Other Cost of Service Exclusions	4,167	-	-	-	-	-	-	-	-
Compliance Adjustment	(6,779)	-	-	-	-	-	-	-	-
Regulated Interest	87,685	83,143	83,813	81,686	77,801	80,365	82,773	78,060	74,009
Return on Rate Base	122,364	126,483	126,720	125,619	116,915	108,087	102,437	99,845	91,810
Average Rate Base	2,306,047	2,310,559	2,321,756	2,325,085	2,329,352	2,379,043	2,500,008	2,604,025	2,630,525
Rate of Return on Rate Base	5.31%	5.47%	5.46%	5.40%	5.02%	4.54%	4.10%	3.83%	3.49%

¹ Numbers may not add due to rounding.

² 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

³ Interest cost of service exclusions primarily relate to the disallowed portion of the debt guarantee fee.

Newfoundland and Labrador Hydro
Schedule D-IV: Average Cost of Debt
(\$000s)

Series	Interest Rate	Year of Issue	Year of Maturity	2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast ¹	2026 Forecast	2027 Test Year
Series V	10.50%	1989	2014	200	-	-	-	-	-	-	-	-	-
Series X	10.25%	1992	2017		-	-	-	-	-	-	-	-	-
Series Y	8.40%	1996	2026	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	-	-
Series AB	6.65%	2001	2031	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Series AD	5.70%	2003	2033	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
Series AF	3.60%	2014	2045	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Series AF	3.60%	2017	2045	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Series 1A	3.70%	2017	2048	-	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
New Issuance - 2017	3.70%	2017	2027	300,000	-	-	-	-	-	-	-	-	-
New Issuance - 2018	3.70%	2018	2048	300,000	-	-	-	-	-	-	-	-	-
Series 1A	3.70%	2018	2048	-	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Series 2A	1.75%	2021	2030	-	-	-	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Series 3A	4.60%	2025	2055	-	-	-	-	-	-	-	300,000	300,000	300,000
Series 4A	4.68%	2026	2056	-	-	-	-	-	-	-	-	200,000	200,000
Series 5A	4.73%	2027	2057	-	-	-	-	-	-	-	-	-	400,000
Total Debentures				1,825,200	1,825,000	1,825,000	2,125,000	2,125,000	2,125,000	2,125,000	2,425,000	2,325,000	2,725,000
Promissory Notes				291,681	233,000	262,000	55,000	131,000	230,000	590,000	279,853	245,261	215,969
Less:													
Sinking Funds				(236,976)	(237,200)	(255,982)	(275,527)	(295,804)	(316,914)	(338,859)	(361,172)	(194,119)	(213,771)
Non-regulated Debt Pool				(11,067)	(22,052)	(15,576)	(14,812)	(2,711)	13,490	2,775	-	-	-
Unamortized Debt Discount and Financing				23,161	20,768	20,413	6,855	8,194	9,589	11,043	9,543	10,499	11,335
Total Debt				1,891,999	1,819,516	1,835,855	1,896,516	1,965,679	2,061,165	2,389,959	2,353,224	2,386,641	2,738,533
Average Debt				1,835,109	1,809,454	1,827,686	1,866,186	1,931,098	2,013,422	2,225,562	2,371,592	2,369,933	2,562,587
Embedded Cost of Debt				2019 Test Year	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast¹	2026 Forecast	2027 Test Year
Long-Term Debt				92,475	92,475	92,475	96,220	97,749	97,725	97,725	100,025	94,425	101,992
Accretion of Long-Term Debt				(170)	(170)	(156)	885	1,339	1,394	1,454	1,521	956	836
Amortization of Foreign Exchange Losses				2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157
Debt Guarantee Fee				8,513	8,605	8,624	8,602	8,703	8,794	8,940	9,008	10,327	10,571
Other Interest				4,993	2,853	1,936	(83)	398	2,173	17,565	11,293	3,968	4,785
Interest on Sinking Fund				(11,484)	(11,386)	(12,132)	(12,895)	(13,626)	(14,449)	(15,285)	(15,663)	(8,249)	(7,902)
				96,484	94,534	92,904	94,886	96,720	97,794	112,556	108,341	103,584	112,439
Interest Cost of Service Exclusions ²				(6,302)	(6,348)	(6,348)	(6,326)	(6,724)	(6,761)	(6,824)	(6,848)	(8,253)	(8,792)
Finance Charges				90,182	88,186	86,556	88,560	89,996	91,033	105,732	101,493	95,331	103,647
Embedded Cost of Debt				4.91%	4.87%	4.74%	4.75%	4.66%	4.52%	4.75%	4.28%	4.02%	4.05%

¹ 2025 Forecast is comprised of actuals for the first three quarters and forecast for the fourth quarter.

² Interest cost of service exclusions primarily relate to the disallowed portion of the debt guarantee fee.

Newfoundland and Labrador Hydro
Schedule D-V: Summary of Deferred Charges
(\$000s)¹

	January 1, 2027 Opening Balance	Additions	Dispositions	Amortization	December 31, 2027 Ending Balance
Deferred Charges					
Existing					
Foreign Exchange Losses	32,354	-	-	(2,157)	30,197
Foreign Exchange on Fuel	(1,214)	-	-	-	(1,214)
Conservation Demand Management	6,520	(506)	(48)	-	5,965
Conservation Demand Management - Labrador Interconnected	525	176	48	(75)	674
GRA Hearing Costs ²	-	1,500	-	(375)	1,125
Phase Two Hearing Costs ²	1,705	-	-	(213)	1,492
Asset Disposal	197	-	-	(19)	178
Isolated Supply	(193)	-	193	-	-
Deferred Power Purchases	-	-	-	-	-
Business Systems Transformation Program ^{2,3}	14,491	-	-	(1,878)	12,613
Reliability and Resource Adequacy ²	4,413	650	-	(633)	4,430
Hydraulic Resource Optimization	(183)	-	-	-	(183)
Frequency Converter ²	(1,618)	-	1,618	-	-
Power Purchase Expense Recognition	1,428,718	284,716	-	-	1,713,434
Muskrat Falls Export Revenue Recognition	35,040	5,920	-	-	40,960
Muskrat Falls Power Purchase Agreement Sustaining Capital ²	43,620	9,030	-	(721)	51,929
Holyrood Thermal Generating Station Accelerated Depreciation	(11,443)	-	-	-	(11,443)
Return on Equity	491	-	(491)	-	(0)
Electrification Cost	900	99	-	(54)	945
General Expenses Capitalized	12,251	6,578	-	(389)	18,440
Allowance for Funds Used During Construction	2,117	4,153	-	(50)	6,220
Cloud Cost	1,978	-	-	(322)	1,656
Proposed					
Revenue Deficiency - Island Utility ²	-	60,083	(60,083)	-	-
Revenue Deficiency - Island Industrial ²	-	2,674	(2,674)	-	-
Revenue Deficiency - Labrador Industrial ²	-	1,753	(15)	(248)	1,490
Revenue Deficiency - Labrador Interconnected Rural ²	-	1,679	(53)	-	1,626
Total Deferred Charges	1,570,668	378,505	(61,505)	(7,134)	1,880,534
Less: Deferred Charges Excluded from Rate Base					
Electrification Cost Deferral	(900)				(945)
Power Purchase Expense Recognition	(1,428,718)				(1,713,434)
Muskrat Falls Export Revenue Recognition	(35,040)				(40,960)
Total Deferred Charges for Rate Base	106,010				125,195
Current Year Opening	80,610				106,010
Average Deferred Charges for Rate Base	93,310				115,602

¹ Numbers may not add due to rounding.

² Disposition has been proposed within this application.

³ Board Order No. P.U. 27(2022) approved the recovery of \$6.7 million. Hydro requested approval of an additional \$7.8 million of costs in its recovery of costs associated with information systems assets application, currently before the Board. Disposition has been proposed within this application.

Schedule E



Newfoundland and Labrador Hydro
Schedule E-I: Calculation of Utility Customer Base Rates for July 1, 2027¹
Utility Estimated Customer Billing Impacts - July 1, 2026

	Billing Units ²	Unit	Current Rates July 1, 2025	Billings at Existing Rates (\$)	Proposed July 1, 2026 Rates ³	Revised Billings (\$)	Change (\$)	Change Utility (%)	Estimated Change End Customer ⁴ (%)
Demand (kW)	15,931,248	\$/kW/mo	5.00	79,656,240	5.00	79,656,240			
1st Block - Energy (MWh)	3,780,000	cents/kWh	8.515	321,867,000	8.515	321,867,000			
2nd Block - Winter Energy (MWh)	637,758	cents/kWh	9.698	61,849,770	9.698	61,849,770			
2nd Block - Non-Winter Energy (MWh)	1,427,985	cents/kWh	3.354	47,894,632	3.354	47,894,632			
Total Base Rate				511,267,642		511,267,642	-		
Rate Stabilization Plan Current Plan Adjustment	5,845,743	cents/kWh	0.413	24,142,920	0.067	3,916,648	(20,226,272)	(3.2)	(2.3)
CDM Cost Recovery Adjustment	5,845,743	cents/kWh	0.019	1,110,691	0.019	1,110,691	-	0.0	0.0
Project Cost Recovery Rider	5,845,743	cents/kWh	1.516	88,621,471	2.220	129,776,976	41,155,506	6.6	4.6
Total				625,142,725		646,071,958	20,929,233	3.3	2.3

¹ Numbers may not add due to rounding.

² Billing units are based on 2025 forecast.

³ Proposed July 1, 2026 rates were estimated at a point in time, actual rates may differ.

⁴ Estimated Change End Customer is based on the estimated flow through rate as provided by Newfoundland Power for Hydro's July 1, 2025 Utility Rate Adjustment Application.

Newfoundland and Labrador Hydro
Schedule E-I: Calculation of Utility Customer Base Rates for July 1, 2027¹
Project Cost Recovery Rider Included in New Base Rate

	Billing Units ²	Unit	Proposed July 1, 2026 Rates ³	Billings at Existing Rates (\$)	July 1, 2026 Rates - Base Rate Conversion	Revised Billings (\$)	Change (\$)	Change Utility (%)	Estimated Change End Customer ⁴ (%)
Demand (kW)	15,931,248	\$/kW/mo	5.00	79,656,240	5.500	87,621,864			
1st Block - Energy (MWh)	3,780,000	cents/kWh	8.515	321,867,000	11.815	446,598,500			
2nd Block - Winter Energy (MWh)	637,758	cents/kWh	9.698	61,849,770	8.958	57,130,361			
2nd Block - Non-Winter Energy (MWh)	1,427,985	cents/kWh	3.354	47,894,632	3.480	49,693,894			
Total Base Rate				511,267,642		641,044,619	129,776,977	20.1	14.1
Rate Stabilization Plan Current Plan Adjustment	5,845,743	cents/kWh	0.067	3,916,648	0.067	3,916,648	-	0.0	0.0
CDM Cost Recovery Adjustment	5,845,743	cents/kWh	0.019	1,110,691	0.019	1,110,691	-	0.0	0.0
Project Cost Recovery Rider	5,845,743	cents/kWh	2.220	129,776,976	0.000	-	(129,776,976)	(20.1)	(14.1)
Total				646,071,958		646,071,958	-	-	-

¹ Numbers may not add due to rounding.

² Billing units are based on 2025 forecast.

³ Proposed July 1, 2026 rates were estimated at a point in time, actual rates may differ.

⁴ Estimated Change End Customer is based on the estimated flow through rate as provided by Newfoundland Power for Hydro's July 1, 2025 Utility Rate Adjustment Application.

Newfoundland and Labrador Hydro
Schedule E-I: Calculation of Utility Customer Base Rates for July 1, 2027
New Base Rate Applied to 2027 Test Year Billing Units

	Billing Units ¹	Unit	July 1, 2026 Rates - Base Rate Conversion ²	Billings at Existing Rates (\$)	Proposed July 1, 2027 Rates ³	Revised Billings (\$)	Change (\$)	Change Utility (%)	Estimated Change End Customer ⁴ (%)
Demand (kW)	16,860,014	\$/kW/mo	5.50	92,730,079	5.500	92,730,079			
1st Block - Energy (MW)	3,000,000	cents/kWh	11.815	354,450,000	11.815	354,450,000			
2nd Block - Winter Energy (MW)	1,546,626	cents/kWh	8.958	138,546,777	8.958	138,546,777			
2nd Block - Non-Winter Energy (MW)	1,467,956	cents/kWh	3.480	51,084,861	3.480	51,084,861			
Total Base Rate				636,811,717		636,811,717	-	0.0	0.0
Rate Stabilization Plan Current Plan Adjustment	6,014,582	cents/kWh	0.067	4,029,770	0.067	4,029,770	-	0.0	0.0
CDM Cost Recovery Adjustment	6,014,582	cents/kWh	0.019	1,142,771	0.019	1,142,771	-	0.0	0.0
Project Cost Recovery Rider	6,014,582	cents/kWh	0.000	-	0.352	21,199,395	21,199,395	3.3	2.3
Total				641,984,258		663,183,653	21,199,395	3.3	2.3

¹ 2027 Test Year billing units.

² Forecast proposed July 1, 2026 rates were estimated at a point in time, actual rates may differ.

³ There is no increase to the Project Cost Recovery Rider as of July 1, 2027 being proposed within Hydro's GRA. This is for illustrative purposes only to show that the rate as of July 1, 2027 is forecast to increase to target the 2.25% domestic end customer rate increase, as required by the rate mitigation plan. This is forecast and actuals may differ. Adjustments to the Project Cost Recovery Rider for July 1, 2027 will be proposed in Hydro's July 1, 2027 Utility Rate Adjustment Application.

⁴ Estimated Change End Customer is based on the estimated flow through rate as provided by Newfoundland Power for Hydro's July 1, 2025 Utility Rate Adjustment Application.

Schedule E-II – LED Light Cost Components¹

Cost Component	LED 100	LED 150	LED 250	LED 400
Energy Profile				
Loading Watts	45.1	66.0	103.4	209.0
kWh/year at 4,380 hours of use	198	289	453	915
Equipment Costs				
Fixture Cost, including Fixture, Arm, Photocell, and Overheads	\$809.22	\$879.37	\$952.99	\$1,071.25
Cost of Overhead Services - Duplex	\$115.55	\$115.55	\$115.55	\$115.55
Total Equipment Cost	\$924.77	\$994.92	\$1,068.54	\$1,186.80
Equipment Carrying Charges				
Fixture, 4.4% Depreciation Rate	\$74.22	\$80.66	\$87.41	\$98.26
Overhead Services - Duplex, 2.5% Depreciation Rate	\$8.22	\$8.22	\$8.22	\$8.22
Total Equipment Carrying Charges	\$82.44	\$88.88	\$95.63	\$106.48
Operating and Maintenance Costs				
Operating and Maintenance	\$43.05	\$43.05	\$43.05	\$43.05
System Costs				
System Cost @ 3.17 cents/kWh, 2027 Test Year Units and Dollars	\$6.27	\$9.15	\$14.34	\$28.97
Subtotal	\$131.77	\$141.08	\$153.02	\$178.50
Other Costs				
Rural Deficit @ 11%	\$14.41	\$15.43	\$16.73	\$19.52
Total Annual Cost	\$146.18	\$156.51	\$169.75	\$198.00
Total Monthly Cost	\$12.18	\$13.04	\$14.15	\$16.50
Proposed Monthly Rate	\$12.18	\$13.04	\$14.15	\$16.50
Number of Lights, Assuming all LEDs for Estimate	1,835	174	74	157
Proposed Revenue	\$268,204	\$27,228	\$12,565	\$31,086

¹ Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
Schedule E-III: Comparison of Existing and Proposed Rates
Labrador Interconnected System and Government Diesel

	Current Rate	Proposed Rate
Rate 1.1L Domestic		
Basic Customer Charge (\$/month)	6.87	7.02
Energy (¢/kWh)	3.154	3.225
Minimum Monthly Charge (\$/ month)	6.87	7.02
Rate 2.1L General Service (0–10 kW)		
Basic Customer Charge (\$/month)		
Unmetered (\$/month)	6.27	6.50
Single Phase (\$/month)	10.27	10.50
Three Phase (\$/month)	16.27	16.50
Energy (¢/kWh)	4.911	5.024
Minimum		
Unmetered (\$/month)	6.27	6.50
Single Phase (\$/month)	10.27	10.50
Three Phase (\$/month)	20.00	20.00
Rate 2.2L General Service (10–100 kW)		
Basic Customer Charge (\$/month)		
Unmetered (\$/month)	6.27	6.50
Single Phase (\$/month)	10.27	10.50
Three Phase (\$/month)	16.27	16.50
Demand (\$/kW)	1.71	1.75
Energy (¢/kWh)	2.338	2.391
Maximum		
Energy (¢/kWh)	6.800	6.800
Minimum		
Demand (\$/kW)	1.05	1.05
Rate 2.3L General Service (110–1000 kVA)		
Demand (\$/kW)	1.91	1.95
Energy (¢/kWh)	2.026	2.073
Maximum		
Energy (¢/kWh)	6.800	6.800
Minimum		
Demand (\$/kVA)	1.05	1.05
Rate 2.4L General Service (1000 kVA and Over)		
Demand (\$/kW)	1.66	1.70
Energy (¢/kWh)	1.675	1.710
Maximum		
Energy (¢/kWh)	6.800	6.800
Minimum		
Demand (\$/kVA)	1.05	1.05
Rate 4.1L Street and Area Lighting		
250 W Mercury Vapour (\$/month)	14.94	14.94
100 W High Pressure Sodium (\$/month)	11.08	11.08
150 W High Pressure Sodium (\$/month)	14.94	14.94
250 W High Pressure Sodium (\$/month)	19.71	19.71
400 W High Pressure Sodium (\$/month)	25.47	25.47
Wood Poles (\$/month)	3.76	3.84
100 W High Pressure Sodium Closed (\$/month)	7.68	7.85
100 W High Pressure Sodium (\$/month)	4.53	4.63
Wood Poles Closed (\$/month)	3.68	3.76
LED 100		12.18
LED 150		13.04
LED 250		14.15
LED 400		16.50

Newfoundland and Labrador Hydro
Schedule E-III: Comparison of Existing and Proposed Rates
Labrador Interconnected System and Government Diesel

	Current Rate	Proposed Rate
Rate 1.2G Domestic Diesel		
Basic Customer Charge (\$/month)	58.95	60.47
Energy (¢/kWh)	100.145	112.853
Rate 2.1G General Service Diesel (0–10 kW)		
Basic Customer Charge (\$/month)	59.82	61.93
Energy (¢/kWh)	85.567	100.955
Rate 2.2G General Service Diesel (Over 10 kW)		
Basic Customer Charge (\$/month)	71.78	76.19
Demand (\$/kW)	65.23	71.92
Energy (¢/kWh)	63.394	71.188
Rate 4.1G Street and Area Lighting Diesel		
Mercury Vapour		
250 W (9,400 lumens) (\$/month)	\$86.83	
High Pressure Sodium		
100 W (8,600 lumens) (\$/month)	\$58.31	
150 W (14,400 lumens) (\$/month)	\$86.83	
Light Emitting Diode		
LED 100		\$58.62
LED 150		\$85.18
Labrador Industrial Rate		
Transmission Demand (\$/kW)	1.08	2.00

Schedule F



NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total System Revenue Requirement

Line No.	1 Description	2 Total Amount (\$)	3 Island Interconnected (\$)	4 Island Isolated (\$)	5 Labrador Isolated (\$)	6 L'Anse au Loup (\$)	7 Labrador Interconnected (\$)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	156,361,556	120,418,337	5,763,854	15,269,542	2,238,392	12,671,431	Detailed Analysis
2	Fuels - No. 6 Fuel	65,010,009	65,010,009	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	22,311,830	2,016,430	2,124,200	17,415,200	756,000	-	Detailed Analysis
4	Fuels - Gas Turbine	18,989,062	18,829,333	-	-	-	159,728	
5	Fuel Supply Deferral	-	-	-	-	-	-	
6	Power Purchases -CF(L)Co	1,554,061	-	-	-	-	1,554,061	Detailed Analysis
7	Power Purchases - Other	65,357,539	60,766,346	177,100	309,793	4,104,300	-	Detailed Analysis
8	Power Purchases - MF	269,134,556	269,134,556	-	-	-	-	Detailed Analysis
9	Total Exports	(40,178,593)	(40,178,593)	-	-	-	-	Detailed Analysis
10	Power Purchases - LTA Costs	46,146,683	46,146,683	-	-	-	-	Detailed Analysis
11	Power Purchases - LIL Costs	465,082,406	465,082,406	-	-	-	-	Detailed Analysis
12	Rate Mitigation	(501,963,983)	(501,963,983)	-	-	-	-	
13	Tariff Revenue	(18,337,593)	(18,337,593)	-	-	-	-	Detailed Analysis
14	Depreciation	114,921,995	100,512,135	1,117,417	5,466,481	1,420,232	6,405,729	Detailed Analysis
	Expense Credits:	-	-	-	-	-	-	
15	Sundry	(511,404)	(393,846)	(18,852)	(49,941)	(7,321)	(41,444)	Total O&M Expenses
16	Greenhouse Gas Carbon Credits	(1,250,000)	(1,250,000)	-	-	-	-	Detailed Analysis
17	Building Rental Income	(6,000)	(6,000)	-	-	-	-	Detailed Analysis
18	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
19	Suppliers' Discounts	-	-	-	-	-	-	Total O&M Expenses
20	Pole Attachments	(1,635,600)	(1,196,656)	(20,860)	(107,593)	(61,423)	(249,068)	Detailed Analysis
21	Wheeling Revenues	-	-	-	-	-	-	Island Interconnected
22	Application Fees	(20,628)	(10,956)	(216)	(1,176)	(432)	(7,848)	Detailed Analysis
23	Meter Test Revenues	-	-	-	-	-	-	Weighted Customers
24	Total Expense Credits	(3,423,632)	(2,857,458)	(39,928)	(158,711)	(69,176)	(298,359)	
25	Subtotal Expenses	660,965,895	584,578,607	9,142,643	38,302,306	8,449,749	20,492,589	
26	Disposal Gain/Loss	-	-	-	-	-	-	Detailed Analysis
27	Subtotal Rev Req Excl Return	660,965,895	584,578,607	9,142,643	38,302,306	8,449,749	20,492,589	
28	Return on Debt	84,343,056	73,763,124	778,420	3,616,593	807,239	5,377,680	Rate Base
29	Return on Equity	52,399,174	45,826,260	483,603	2,246,853	501,507	3,340,951	Rate Base
30	Total Revenue Requirement	797,708,125	704,167,991	10,404,667	44,165,752	9,758,496	29,211,220	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total System
Return on Rate Base

Line No	1	2	3	4	5	6	7	8
	Total \$	Island Interconnected \$	Island Isolated \$	Labrador Isolated \$	L'Anse au Loup \$	Labrador Interconnected \$		Basis of Proration
Rate Base:								
1	Average Net Book Value	2,404,120,916	2,102,740,030	21,518,581	95,513,749	24,686,846	159,661,709	Schedule F 2.3
2	Cash Working Capital	1,562,000	1,366,187	13,981	62,057	16,039	103,735	Prorated on Average Net Book Value - L. 1
3	Cash Working Capital - Muskrat Falls	115,124,000	115,124,000	-	-	-	-	Detailed Analysis
4	Fuel Inventory - No. 6 Fuel	53,963,965	53,963,965	-	-	-	-	Specifically Assigned - Holyrood
5	Fuel Inventory - Diesel	6,181,464	180,546	206,653	5,700,591	93,674	-	Detailed Fuel Analysis
6	Fuel Inventory - Gas Turbine	7,883,571	7,763,006	-	-	-	120,566	Detailed Fuel Analysis
7	Inventory/Supplies	44,722,000	39,481,123	217,603	1,653,208	473,133	2,896,934	Prorated on Total Plant in Service, Schedule F 2.2
8	Deferred Charges: Muskrat Falls	47,775	47,775	-	-	-	-	Detailed Analysis
	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	115,554,722	101,068,768	1,034,296	4,590,894	1,186,580	7,674,183	Prorated on Average Net Book Value - L. 1
10	Retired Asset Pool	52,934,464	28,866,724	2,870,021	12,632,077	362,309	8,203,333	Assigned by System
11	Total Rate Base	2,802,094,876	2,450,602,123	25,861,135	120,152,576	26,818,581	178,660,460	
12	Less: Rural Portion	-	-	-	-	-	-	Schedule F 2.6, L. 11
13	Rate Base Available for Equity Return	2,802,094,876	2,450,602,123	25,861,135	120,152,576	26,818,581	178,660,460	
Corporate Targets:								
14	Capital Structure: Percent of Debt	74.50% ⁽¹⁾						
15	Return	4.05%						
16	Weighted Average Return: Debt	3.01%						
17	Capital Structure: Percent of Equity	21.75% ⁽¹⁾						
18	Return	8.60%						
19	Weighted Average Return: Equity	1.87%						
20	Weighted Average Cost of Capital	4.88%						
Return on Rate Base by System (%):								
21	Return on Rate Base - Debt Component	-	3.01%	3.01%	3.01%	3.01%	3.01%	
22	Return on Rate Base - Equity Component	-	1.87%	1.87%	1.87%	1.87%	1.87%	
Return on Rate Base (\$):								
23	Return on Debt	84,343,056	73,763,124	778,420	3,616,593	807,239	5,377,680	Schedule F 2.6, L.13
24	Return on Equity	52,399,174	45,826,260	483,603	2,246,853	501,507	3,340,951	Schedule F 2.6, L.14
25	Return on Rate Base (\$)	136,742,230	119,589,384	1,262,023	5,863,446	1,308,747	8,718,630	Schedule F 2.6, L.15
Return on Total Rate Base (%):								
26	Return on Rate Base - Debt Component	3.01%	3.01%	3.01%	3.01%	3.01%	3.01%	L. 23 divided by L.11
27	Return on Rate Base - Equity Component	1.87%	1.87%	1.87%	1.87%	1.87%	1.87%	L. 24 divided by L.11
28	Return on Rate Base (%)	4.88%	4.88%	4.88%	4.88%	4.88%	4.88%	L. 25 divided by L.11

⁽¹⁾ Debt and equity weightings reflect a 0.74% funded ARO and 3.01% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credits (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	Total System						
1	Newfoundland Power	636,811,717	574,037,014	-	62,778,788	636,815,801	
2	RSP Activity	-	-	-	-	-	
3	Subtotal Newfoundland Power	636,811,717	574,037,014	-	62,778,788	636,815,801	1.11
4	Island Industrial	42,815,529	42,815,548	-	-	42,815,548	1.00
5	Unallocated RSP Hydraulic Variation	-	-	-	-	-	-
6	Labrador Industrial	9,171,998	9,172,200	-	-	9,172,200	1.00
7	CFB - Goose Bay Secondary	-	-	-	-	-	-
8	Rural Labrador Interconnected	22,231,036	20,039,020	-	2,191,541	22,230,560	1.11
	Rural Deficit Areas						
9	Island Interconnected	68,909,058	87,315,429	-	(18,406,371)	68,909,058	0.79
10	Island Isolated	1,717,949	10,404,402	-	(8,686,453)	1,717,949	0.17
11	Labrador Isolated	11,969,343	44,165,488	-	(32,196,145)	11,969,343	0.27
12	L'Anse au Loup	4,077,137	9,758,496	-	(5,681,359)	4,077,137	0.42
13	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
14	Subtotal	86,673,487	151,643,815	-	(64,970,328)	86,673,487	0.57
15	Total	797,703,766	797,707,596	-	-	797,707,596	1.00

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Interconnected							
1	Newfoundland Power	636,811,717	574,037,014	-	62,778,788	636,815,801	
2	NLP RSP Activity	-				-	
3	Subtotal Newfoundland Power	636,811,717	574,037,014	-	62,778,788	636,815,801	1.11
4	Industrial - Firm	42,815,529	42,815,548	-		42,815,548	
5	Industrial - Non-Firm	-	-	-		-	
6	Industrial RSP Activity	-				-	
7	Subtotal Industrial	42,815,529	42,815,548	-	-	42,815,548	1.00
8	Unallocated RSP Hydraulic Variation	-					
Rural							
9	1.1 Domestic	18,788,948	28,157,867	-	(9,368,919)	18,788,948	0.67
10	1.12 Domestic All Electric	23,929,645	31,353,543	-	(7,423,897)	23,929,645	0.76
11	1.3 Special	21,704	86,780	-	(65,076)	21,704	0.25
12	2.1 General Service 0-100 kW	12,084,583	13,595,527	-	(1,510,943)	12,084,583	0.89
13	2.3 General Service 110-1,000 kVa	7,645,700	7,883,736	-	(238,035)	7,645,700	0.97
14	2.4 General Service Over 1,000 kVa	5,260,869	4,783,802	-	477,068	5,260,869	1.10
15	4.1 Street and Area Lighting	1,177,608	1,454,176	-	(276,568)	1,177,608	0.81
16	Subtotal Rural	68,909,058	87,315,429	-	(18,406,371)	68,909,058	0.79
17	Total Island Interconnected	748,536,304	704,167,991	-	44,372,416	748,540,407	1.06

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		(\$)	(\$)	(\$)	(\$)	(\$)	
	Island Isolated						
1	1.2 Domestic Diesel	809,510	7,704,844		(6,895,334)	809,510	0.11
2	1.2G Government Domestic Diesel	-	55,464		(55,464)	-	-
3	1.23 Churches, Schools & Com Halls	54,843	367,319		(312,476)	54,843	0.15
4	2.1 General Service 0-10 kW	285,054	823,425		(538,370)	285,054	0.35
5	2.2 GS 10-100 kW	535,299	1,290,296		(754,997)	535,299	0.41
6	2.3 GS 110-1,000 kVa	-	-		-	-	-
7	2.4 General Service Over 1,000 kVa	-	-		-	-	-
8	4.1 Street and Area Lighting	26,859	163,053		(136,195)	26,859	0.16
9	4.1G Gov't Street and Area Lighting	6,384	-		6,384	6,384	-
10	Total	1,717,949	10,404,402		(8,686,453)	1,717,949	0.17

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Isolated							
1	1.2 Domestic Diesel	4,669,502	25,171,515		(20,502,013)	4,669,502	0.19
2	1.2G Government Domestic Diesel	945,104	894,393		50,711	945,104	1.06
3	1.23 Churches, Schools & Com Halls	328,742	1,337,649		(1,008,907)	328,742	0.25
4	2.1 General Service 0-10 kW	1,505,530	3,692,362		(2,186,832)	1,505,530	0.41
5	2.2 GS 10-100 kW	3,760,679	9,555,598		(5,794,920)	3,760,679	0.39
6	2.3 GS 110-1,000 kVa	364,087	1,830,407		(1,466,319)	364,087	0.20
7	2.4 General Service Over 1,000 kVa	245,160	1,373,675		(1,128,515)	245,160	0.18
8	4.1 Street and Area Lighting	144,155	309,889		(165,734)	144,155	0.47
9	4.1G Gov't Street and Area Lighting	6,384	-		6,384	6,384	-
10	Total	11,969,343	44,165,488		(32,196,145)	11,969,343	0.27

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	L'Anse au Loup						
1	1.1 Domestic	828,511	2,224,304		(1,395,792)	828,511	0.37
2	1.12 Domestic All Electric	1,782,547	4,421,637		(2,639,090)	1,782,547	0.40
3	2.1 General Service 0-100 kW	1,046,118	2,332,950		(1,286,832)	1,046,118	0.45
4	2.2 General Service 10-100 kW	-	-		-	-	-
5	2.3 General Service 110-1,000 kVa	354,037	690,869		(336,832)	354,037	0.51
6	4.1 Street and Area Lighting	65,923	88,737		(22,814)	65,923	0.74
7	Total L'Anse Au Loup	4,077,137	9,758,496		(5,681,359)	4,077,137	0.42

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected						
1	Labrador Industrial Firm	9,171,998	9,172,200	-	-	9,172,200	1.00
2	Labrador Industrial Non-Firm	-	-	-	-	-	-
3	Subtotal Industrial	9,171,998	9,172,200	-	-	9,172,200	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
	Rural						
5	1.1 Domestic	106,057	206,448	-	22,577.87	229,025	0.46
6	1.1A Domestic All Electric	11,783,491	12,172,687	-	1,331,250	13,503,937	0.87
7	2.1 General Service 0-10 kW	302,008	302,668	-	33,101	335,769	0.90
8	2.2 General Service 10-100 kW	2,488,347	1,963,429	-	214,728	2,178,157	1.14
9	2.3 General Service 110-1,000 kVa	4,254,476	2,864,082	-	313,226	3,177,308	1.34
10	2.4 General Service Over 1,000 kVa	2,903,849	2,090,121	-	228,583	2,318,705	1.25
11	4.1 Street and Area Lighting	392,808	439,585	-	48,075	487,659	0.81
12	Subtotal Rural	22,231,036	20,039,020	-	2,191,541	22,230,560	
13	Total Labrador Interconnected	31,403,034	29,211,220	-	2,191,541	31,402,760	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total System
Rural Deficit Allocation

Line No.	1	2			
			Deficit Allocation Allocated on Revenue Requirement	Island Interconnected	Labrador Interconnected
			(\$)	(\$)	(\$)
	ALLOCATION OF DEFICIT:				
1	Rural Deficit Classified	64,970,328			
2	Allocated Totals	64,970,328	62,778,788	2,191,541	
	CUSTOMER DEFICIT ALLOCATION:				
		Amount	Revenue Requirement	Percent	
	Island Interconnected:				
3	Newfoundland Power	62,778,788	574,037,014	96.6%	
	Labrador Interconnected:				
4	Rural Labrador Interconnected	2,191,541	20,039,020	3.4%	
5	Total	64,970,328		100.0%	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line No.		Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)
	Island Interconnected										
1	Newfoundland Power	20.40	-	0.03779	-	228,611.94	22.64	-	0.04192	-	253,613.78
2	Industrial - Firm	17.54	-	0.03780	-	5,739.81	17.54	-	0.03780	-	5,739.81
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
	Rural										
4	1.1 Domestic	-	0.16589	0.04168	0.20757	40.39	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.14311	0.04177	0.18487	40.47	-	-	-	-	-
6	1.3 Special	-	0.20879	0.04135	0.25014	40.07	-	-	-	-	-
7	2.1 General Service 0-10 kW	33.69	-	0.04195	-	59.66	-	-	-	-	-
8	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	32.31	-	0.04188	-	78.26	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	24.58	-	0.04065	-	78.10	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.16654	0.04193	0.20847	80.55	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11	
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation					
Line No.		Demand		Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand		Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	
		Demand (\$/kW)	Non-Demand (\$/kWh)				Demand (\$/kW)	Non-Demand (\$/kWh)				
Isolated Systems:												
1	1.2 Domestic Diesel	-	0.40411	0.70486	1.10897	59.48						
2	2.1 General Service 0-10 kW	-	0.28507	0.70790	0.99296	60.91						
3	2.2 GS 10-100 kW	70.74	-	0.70018	-	74.94						
4	2.3 GS 110-1,000 kVa	18.45	-	0.68590	-	92.09						
5	2.4 General Service Over 1,000 kVa	25.89	-	0.68603	-	92.10						
6	Subtotal Metered Demand Classes	57.16	-	0.69628	-	75.82						
7	4.1 Street and Area Lighting	-	0.41845	0.71159	1.13004	125.84						
Island Isolated												
8	1.2 Domestic Diesel	-	0.93339	0.81837	1.75176	98.56	-	-	-	-	-	
9	2.1 General Service 0-10 kW	-	0.49421	0.82234	1.31655	108.37	-	-	-	-	-	
10	2.2 GS 10-100 kW	176.03	-	0.82560	-	150.09	-	-	-	-	-	
11	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	
12	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	
13	4.1 Street and Area Lighting	-	0.88062	0.82195	1.70257	258.93	-	-	-	-	-	
Labrador Isolated												
14	1.2 Domestic Diesel	-	0.31708	0.68619	1.00327	49.95	-	-	-	-	-	
15	2.1 General Service 0-10 kW	-	0.25281	0.69024	0.94305	53.23	-	-	-	-	-	
16	2.2 GS 10-100 kW	61.91	-	0.68978	-	70.62	-	-	-	-	-	
17	2.3 GS 110-1,000 kVa	18.45	-	0.68590	-	92.09	-	-	-	-	-	
18	2.4 General Service Over 1,000 kVa	25.89	-	0.68603	-	92.10	-	-	-	-	-	
19	4.1 Street and Area Lighting	-	0.32940	0.69032	1.01972	89.05	-	-	-	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand		Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand		Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)
		Demand (\$/kW)	Non-Demand (\$/kWh)				Demand (\$/kW)	Non-Demand (\$/kWh)			
L'Anse au Loup											
1	1.1 Domestic	-	0.20909	0.19648	0.40557	45.67	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.17611	0.19663	0.37274	45.70	-	-	-	-	-
3	2.1 General Service 0-10 kW	39.65	-	0.19714	-	62.03	-	-	-	-	-
4	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	24.22	-	0.19724	-	77.75	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.19152	0.19613	0.38764	139.21	-	-	-	-	-
Labrador Interconnected											
7	Labrador Industrial - Firm	2.40	-	-	-	-	2.40	-	-	-	-
8	Labrador Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
9	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-
Rural											
10	1.1 Domestic	-	0.02547	0.00153	0.02700	38.32	-	0.02826	0.00169	0.02995	42.51
11	1.1A Domestic All Electric	-	0.02181	0.00155	0.02336	38.79	-	0.02420	0.00172	0.02591	43.04
12	Subtotal Domestic	-	0.02184	0.00155	0.02338	38.78	-	0.02422	0.00172	0.02594	43.02
13	2.1 General Service 0-10 kW	-	0.01650	0.00156	0.01806	43.34	-	0.01831	0.00173	0.02004	48.08
14	2.2 General Service 10-100 kW	5.33	-	0.00156	-	57.22	5.91	-	0.00173	-	63.48
15	2.3 General Service 110-1,000 kVa	5.43	-	0.00156	-	75.01	6.03	-	0.00173	-	83.21
16	2.4 General Service Over 1,000 kVa	7.81	-	0.00154	-	75.75	8.66	-	0.00171	-	84.03
17	4.1 Street and Area Lighting	-	0.02190	0.00154	0.02344	87.30	-	0.02429	0.00171	0.02601	96.84

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	Island Interconnected								
1	Newfoundland Power	574,037,014	344,018,735	227,274,935	2,743,343	636,815,801	381,641,882	252,130,554	3,043,365
2	Industrial - Firm	42,815,548	19,217,532	23,184,750	413,266	42,815,548	19,217,532	23,184,750	413,266
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-
	Rural								
4	1.1 Domestic	28,157,867	18,051,308	4,535,571	5,570,987	-	-	-	-
5	1.12 Domestic All Electric	31,353,543	20,994,435	6,127,194	4,231,914	-	-	-	-
6	1.3 Special	86,780	72,033	14,266	481	-	-	-	-
7	2.1 General Service 0-10 kW	13,595,527	8,362,762	3,055,240	2,177,525	-	-	-	-
8	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	7,883,736	5,524,750	2,280,566	78,419	-	-	-	-
10	2.4 General Service Over 1,000 kVa	4,783,802	3,138,658	1,637,646	7,498	-	-	-	-
11	4.1 Street and Area Lighting	1,454,176	345,866	87,081	1,021,229	-	-	-	-
12	Subtotal Rural	87,315,429	56,489,812	17,737,564	13,088,053				
13	Total Island Interconnected	704,167,991	419,726,078	268,197,249	16,244,663				

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	Isolated Systems:								
1	1.2 Domestic Diesel	35,531,185	12,225,414	21,323,744	1,982,027				
2	2.1 General Service 0-10 kW	4,515,787	1,202,109	2,985,134	328,544				
3	2.2 GS 10-100 kW	10,845,894	3,018,652	7,711,419	115,823				
4	2.3 GS 110-1,000 kVa	1,830,407	192,285	1,631,491	6,630				
5	2.4 General Service Over 1,000 kVa	1,373,675	145,946	1,226,624	1,105				
6	Subtotal Metered Demand Classes	14,049,976	3,356,883	10,569,534	123,559				
7	4.1 Street and Area Lighting	472,942	87,340	148,522	237,081				
8	Total Isolated Systems	54,569,890	16,871,746	35,026,934	2,671,210				
	Island Isolated								
9	1.2 Domestic Diesel	8,127,627	3,987,492	3,496,117	644,019	-	-	-	-
10	2.1 General Service 0-10 kW	823,425	278,519	463,439	81,467	-	-	-	-
11	2.2 GS 10-100 kW	1,290,296	581,615	696,073	12,608	-	-	-	-
12	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-
14	4.1 Street and Area Lighting	163,053	29,695	27,716	105,642	-	-	-	-
15	Total Island Isolated	10,404,402	4,877,320	4,683,345	843,737				
	Labrador Isolated								
16	1.2 Domestic Diesel	27,403,557	8,237,923	17,827,627	1,338,008	-	-	-	-
17	2.1 General Service 0-10 kW	3,692,362	923,590	2,521,695	247,077	-	-	-	-
18	2.2 GS 10-100 kW	9,555,598	2,437,037	7,015,346	103,215	-	-	-	-
19	2.3 GS 110-1,000 kVa	1,830,407	192,285	1,631,491	6,630	-	-	-	-
20	2.4 General Service Over 1,000 kVa	1,373,675	145,946	1,226,624	1,105	-	-	-	-
21	4.1 Street and Area Lighting	309,889	57,645	120,806	131,438	-	-	-	-
22	Total Labrador Isolated	44,165,488	11,994,426	30,343,589	1,827,473				

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	L'Anse au Loup								
1	1.1 Domestic	2,224,304	1,029,886	967,807	226,610	-	-	-	-
2	1.12 Domestic All Electric	4,421,637	1,965,011	2,193,923	262,703	-	-	-	-
3	2.1 General Service 0-10 kW	2,332,950	912,221	1,275,212	145,517	-	-	-	-
4	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	690,869	222,020	462,718	6,131	-	-	-	-
6	4.1 Street and Area Lighting	88,737	12,479	12,780	63,478	-	-	-	-
7	Total L'Anse au Loup	9,758,496	4,141,617	4,912,440	704,439				
	Labrador Interconnected								
8	Labrador Industrial - Firm	9,172,200	9,127,445	-	44,754	9,172,200	9,127,445	-	44,754
9	Labrador Industrial - Non-Firm	-	-	-	-	-	-	-	-
10	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-
	Rural								
11	1.1 Domestic	206,448	57,902	3,472	145,073	229,025	64,234	3,852	160,939
12	1.1A Domestic All Electric	12,172,687	6,989,193	495,604	4,687,891	13,503,937	7,753,556	549,805	5,200,576
13	Subtotal Domestic	12,379,135	7,047,094	499,076	4,832,965	13,732,963	7,817,791	553,657	5,361,515
14	2.1 General Service 0-10 kW	302,668	72,906	6,891	222,871	335,769	80,880	7,645	247,245
15	2.2 General Service 10-100 kW	1,963,429	1,326,045	116,569	520,815	2,178,157	1,471,066	129,318	577,773
16	2.3 General Service 110-1,000 kVa	2,864,082	2,445,074	242,120	176,888	3,177,308	2,712,476	268,599	196,233
17	2.4 General Service Over 1,000 kVa	2,090,121	1,862,739	221,928	5,454	2,318,705	2,066,455	246,199	6,050
18	4.1 Street and Area Lighting	439,585	21,166	1,493	416,925	487,659	23,481	1,656	462,522
19	Subtotal Rural	20,039,020	12,775,026	1,088,077	6,175,917	22,230,560	14,172,149	1,207,074	6,851,338
20	Total Labrador Interconnected	29,211,220	21,902,471	1,088,077	6,220,671	31,402,760	23,299,594	1,207,074	6,896,092

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Island Interconnected				
1	Newfoundland Power	16,860,014	6,014,582	1	12
2	Industrial - Firm	1,095,600	613,371	6	72
3	Industrial - Non-Firm	-	-	-	-
	Rural				
4	1.1 Domestic	-	108,816	11,494	137,927
5	1.12 Domestic All Electric	-	146,706	8,714	104,563
6	1.3 Special	-	345	1	12
7	2.1 General Service 0-10 kW	248,253	72,837	3,042	36,498
8	2.2 General Service 10-100 kW	-	-	-	-
9	2.3 General Service 110-1,000 kVa	171,006	54,457	84	1,002
10	2.4 General Service Over 1,000 kVa	127,708	40,282	8	96
11	4.1 Street and Area Lighting	-	2,077	1,057	12,678
12	Subtotal Rural	546,967	425,520	24,398	292,776
13	Total Island Interconnected	18,502,582	7,053,473	24,405	292,860

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Demands, Sales, & Number of Bills

Line No.	Rate Class	1	2	3	4	5
		Units				
		Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)	
	Isolated Systems:					
1	1.2 Domestic Diesel	-	30,253	2,900	33,323	
2	2.1 General Service 0-10 kW	-	4,217	449	5,394	
3	2.2 GS 10-100 kW	42,671	11,014	129	1,546	
4	2.3 GS 110-1,000 kVa	10,423	2,379	6	72	
5	2.4 General Service Over 1,000 kVa	5,638	1,788	1	12	
6	Subtotal Metered Demand Classes	58,732	15,180	136	1,630	
7	4.1 Street and Area Lighting	-	209	157	1,884	
8	Total Isolated Systems	58,732	49,858	3,642	42,230	
	Island Isolated					
9	1.2 Domestic Diesel	-	4,272	560	6,534	
10	2.1 General Service 0-10 kW	-	564	63	752	
11	2.2 GS 10-100 kW	3,304	843	7	84	
12	2.3 GS 110-1,000 kVa	-	-	-	-	
13	2.4 General Service Over 1,000 kVa	-	-	-	-	
14	4.1 Street and Area Lighting	-	34	34	408	
15	Total Island Isolated	3,304	5,712	663	7,778	
	Labrador Isolated					
16	1.2 Domestic Diesel	-	25,980	2,340	26,789	
17	2.1 General Service 0-10 kW	-	3,653	387	4,642	
18	2.2 GS 10-100 kW	39,367	10,170	122	1,462	
19	2.3 GS 110-1,000 kVa	10,423	2,379	6	72	
20	2.4 General Service Over 1,000 kVa	5,638	1,788	1	12	
21	4.1 Street and Area Lighting	-	175	123	1,476	
22	Total Labrador Isolated	55,428	44,146	2,979	34,453	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Demands, Sales, & Number of Bills

Line No.	Rate Class	1	2	3	4	5
		Units				
		Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)	
L'Anse au Loup						
1	1.1 Domestic	-	4,926	414		4,962
2	1.12 Domestic All Electric	-	11,158	479		5,748
3	2.1 General Service 0-10 kW	23,004	6,468	196		2,346
4	2.2 General Service 10-100 kW	-	-	-		-
5	2.3 General Service 110-1,000 kVa	9,166	2,346	7		79
6	4.1 Street and Area Lighting	-	65	38		456
7	Total L'Anse au Loup	32,170	24,963	1,133		13,591
Labrador Interconnected						
8	Labrador Industrial - Firm	3,804,000	1,902,365	-		-
9	Labrador Industrial - Non-Firm	-	-	-		-
10	CFB - Goose Bay Secondary	-	-	-		-
Rural						
11	1.1 Domestic	-	2,273	316		3,786
12	1.1A Domestic All Electric	-	320,448	10,070		120,840
13	Subtotal Domestic	-	322,721	10,386		124,626
14	2.1 General Service 0-10 kW	-	4,418	429		5,142
15	2.2 General Service 10-100 kW	248,712	74,799	759		9,102
16	2.3 General Service 110-1,000 kVa	449,945	155,037	197		2,358
17	2.4 General Service Over 1,000 kVa	238,486	144,227	6		72
18	4.1 Street and Area Lighting	-	967	398		4,776
19	Subtotal Rural	937,142	702,170	12,173		146,076
20	Total Labrador Interconnected	4,741,142	2,604,535	12,173		146,076

**NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Rate Calculations for Newfoundland Power**

	1	2	3
Line No.	Description	Amount	Source
	Newfoundland Power:		
	Demand:		
1	Rate (\$/kW/mo.)	\$5.50	
2	Billing Units (kW)	16,860,014	Sch F 1.3.2, pg 1, Ln 1, Col 2
3	Demand Revenue	\$92,730,079	Ln 1 * Ln 2
	Energy (First Block):		
4	Total Revenue Requirement	\$636,815,801	Sch F 1.2, pg 1, Ln 1, Col 6
5	Less: Demand Revenue	\$92,730,079	Ln 3
6	Less: Second Block Energy Revenue (winter)	\$138,546,777	Ln 11 * Ln 13
7	Less: Second Block Energy Revenue (non-winter)	\$51,084,861	Ln 14 * Ln 16
8	First Block Energy Revenue	<u>\$354,454,084</u>	Ln 4 - Ln 5 - Ln 6 - Ln 7
9	First Block Energy Consumed (MWh)	3,000,000	
10	Rate (¢/kWh)	11.815	Ln 8 / Ln 9
	Energy (Second Block - Winter):		
11	Energy Consumption (MWh)	1,546,626	
12	Energy Revenue (winter)	\$138,546,777	
13	Rate (¢/kWh)	8.958	
	Energy (Second Block - Non-winter):		
14	Energy Consumption (MWh)	1,467,956	
15	Energy Revenue (non-winter)	\$51,084,861	
16	Rate (¢/kWh)	3.480	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Value of Newfoundland Power Thermal Generation Credit

Line No.	Description	Amount	Source
1	Island Interconnected System:		
2	Generation demand costs (\$)	311,083,726	Sch F 2.1A, C. 3, Ln 31
3	Coincident peak (kW)	1,644,378	Sch F 3.1A, C. 3, Ln 13
4	Generation demand costs (\$/kW)	<u>189.18</u>	Ln 2 / Ln 3
5	NP thermal generation capacity credit (kW)	<u>39,299</u>	⁽¹⁾
6	Gross value of credit to NP (\$)	<u>7,434,585</u>	Ln 4 x Ln 5
7	Less NP's cost share:		
8	Percentage	<u>89.00%</u>	Sch F 3.1A, C. 5, Ln 14
9	Amount (\$)	<u>(6,616,889)</u>	Ln 6 x Ln 8
10	Net value of credit to NP (\$)	<u><u>817,696</u></u>	Ln 6 - Ln 9

⁽¹⁾ NP gas turbine and diesel generation capacity (kW)
+ System reserve
NP thermal generation capacity credit (kW)

44,500
1.132
39,299

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Calculation of Firming Up Charge

	1	2	3	4
Line No.	Description	Total	Gas Turbine	Transmission & Terminals
1	Operating & Maintenance	18,091,849	4,264,846	13,827,003
2	O&M Overhead	15,874,399	4,901,340	10,973,058
3	Depreciation	24,638,245	6,720,131	17,918,114
4	Return	40,542,173	7,359,677	33,182,497
5	Total	99,146,666	23,245,994	75,900,672
6	Capacity (kW)		248,500	1,797,100
7	Cost (\$/kW)	\$135.78	\$93.55	\$42.24
8	Transmission coincident peak ⁽¹⁾	1,435,869		
9	Newfoundland Power Sales (MWh)	6,014,582		
10	Rate (\$/kWh)	\$0.03242		

⁽¹⁾ Newfoundland Power Transmission Coincident Peak adjusted for thermal credit in compliance with PU.8(2007).

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Calculation of Transmission Wheeling Charge

	1	2
Line No.	Description	
1	Island Interconnected Transmission Revenue Requirement	75,818,020
2	Transmission Energy Output (MWh)	7,089,578
3	Rate (\$/kWh)	\$0.01069

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Expenses																	
1	Operating & Maintenance	120,418,337	54,298,912	19,682,217	24,800,061	3,485,290	2,469,383	4,736,713	1,292,255	394,987	699,159	684,343	776,616	228,066	610,124	194,602	3,119,143	532,535
2	Fuels-No. 6 Fuel	65,010,009	-	65,010,009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	2,016,430	2,016,430	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	18,829,333	18,829,333	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Supply Deferral	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Power Purchases-Other	60,766,346	32,646,808	27,159,537	-	960,000	-	-	-	-	-	-	-	-	-	-	-	-
8	Power Purchases-MF	269,134,556	133,794,098	135,340,458	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Exports	(40,178,593)	(19,973,870)	(20,204,723)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Power Purchases - LTA Costs	46,146,683	22,940,770	23,205,914	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Power Purchases - LIL Costs	465,082,406	231,205,096	233,877,310	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate Mitigation	(501,963,983)	(249,539,930)	(252,424,053)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tariff Revenue	(18,337,593)	(9,116,116)	(9,221,477)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Depreciation	100,512,135	52,319,167	16,798,496	17,918,114	2,388,332	1,960,361	3,655,270	1,041,484	320,771	567,792	534,749	618,155	141,706	598,613	233,200	375,105	1,040,820
	Expense Credits																	
15	Sundry	(393,846)	(177,593)	(64,374)	(81,112)	(11,399)	(8,076)	(15,492)	(4,227)	(1,292)	(2,287)	(2,238)	(2,540)	(746)	(1,996)	(636)	(10,202)	(1,742)
16	Greenhouse Gas Carbon Credits	(1,250,000)	(621,409)	(628,591)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Building Rental Income	(6,000)	(2,281)	(1,234)	(1,540)	(232)	(120)	(240)	(65)	(20)	(35)	(35)	(39)	(12)	(18)	(10)	-	(119)
18	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Pole Attachments	(1,196,656)	-	-	-	-	-	(692,084)	(236,521)	-	-	(122,499)	(145,552)	-	-	-	-	-
21	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Application Fees	(10,956)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10,956)	-
24	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Expense Credits	(2,857,458)	(801,283)	(694,199)	(82,652)	(11,631)	(8,196)	(707,816)	(240,813)	(1,312)	(2,322)	(124,772)	(148,131)	(757)	(2,014)	(646)	(21,158)	(1,860)
26	Subtotal Expenses	584,578,607	268,619,415	238,529,488	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495
27	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Subtotal Revenue Requirement Ex. Return	584,578,607	268,619,415	238,529,488	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495
29	Return on Debt	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863
30	Return on Equity	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646
31	Total Revenue Reqmt	704,167,991	311,083,726	267,515,952	75,818,020	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	3,152,004

NEWFOUNDLAND & LABRADOR HYDRO
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Functional Classification of Revenue Requirement (CONT'D.)

Line No.	Description	Revenue Related		Basis of Functional Classification
		Municipal Tax	PUB Assessment	
1	Expenses			
1	Operating & Maintenance	1,436,329	977,601	Carryforward from Sch F 2.4 L.30
2	Fuels-No. 6 Fuel	-	-	Production - Demand, Energy ratios Sch F 4.1 L.10
3	Fuels-Diesel	-	-	Production - Demand, Energy ratios Sch F 4.1 L.12
4	Fuels-Gas Turbine	-	-	Production - Demand, Energy ratios Sch F 4.1 L.11
5	Fuel Supply Deferral	-	-	
6	Power Purchases -CF(L)Co	-	-	
7	Power Purchases-Other	-	-	Carryforward from Sch F 4.4 L.1 - L.7
8	Power Purchases-MF	-	-	Carryforward from Sch F 4.4 L.8
9	Total Exports	-	-	
10	Power Purchases - LTA Costs	-	-	
11	Power Purchases - LIL Costs	-	-	Carryforward from Sch F 4.4 L.10
12	Rate Mitigation	-	-	
13	Tariff Revenue	-	-	Carryforward from Sch F 4.4 L.11
14	Depreciation	-	-	Carryforward from Sch F 2.5 L.42
15	Expense Credits			
15	Sundry	(4,698)	(3,197)	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.30
16	Greenhouse Gas Carbon Credits			
17	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch F 2.2 L.35
18	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.30
19	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.30
20	Pole Attachments	-	-	Prorated on Distribution Poles - Sch F 4.1 L.37
21	Secondary Energy	-	-	Production - Energy
22	Wheeling Revenues	-	-	Transmission - Demand
23	Application Fees	-	-	Accounting - Customer
24	Meter Test Revenues	-	-	Meters - Customer
25	Total Expense Credits	(4,698)	(3,197)	
26	Subtotal Expenses	1,431,632	974,404	
27	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch F 2.3 L.42
28	Subtotal Revenue Requirement Ex. Return	1,431,632	974,404	
29	Return on Debt	-	-	Prorated on Rate Base - Sch F 2.6 L.10
30	Return on Equity	-	-	Prorated on Rate Base - Sch F 2.6 L.12
31	Total Revenue Reqmt	1,431,632	974,404	

NEWFOUNDLAND AND LABRADOR HYDRO
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Island Interconnected

Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution Substations Demand	Primary Lines Demand	Line Transformers Customer Demand	Secondary Lines Customer Demand	Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Specifically Assigned Customer			
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
	Production Hydraulic																	
1	Bay D'Espoir	1,114,924,927	554,259,464	560,665,463	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	700,315	348,145	352,169	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	2,313,263	1,149,986	1,163,277	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	1,149,439	571,417	578,022	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	219,265	109,003	110,263	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	1,090,425	542,080	548,345	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Star Lake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other Hydraulic	282,500	140,438	142,062	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Subtotal Hydraulic	1,120,680,135	557,120,534	563,559,601	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Holyrood	437,045,123	388,270,887	48,774,236	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Turbines	200,469,524	200,469,524	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Diesel	12,942,773	12,942,773	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal Production	1,771,137,554	1,158,803,718	612,333,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
16	Lines	678,735,396	16,819,819	17,014,219	510,359,668	93,873,902	-	-	-	-	-	-	-	-	-	-	-	40,667,788
17	Terminal Stations	364,335,330	-	-	311,535,934	30,123,467	-	-	-	-	-	-	-	-	-	-	-	22,675,929
18	Term Stns - Hydraulic	55,383,108	27,532,447	27,850,661	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Holyrood	15,948,999	14,169,091	1,779,908	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Gas Tur/Dsl	453,488	453,488	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Term Stns - Distribution	19,394,860	-	-	-	-	19,394,860	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal Term Stns	455,515,786	42,155,026	29,630,569	311,535,934	30,123,467	19,394,860	-	-	-	-	-	-	-	-	-	-	22,675,929
23	Subtotal Transmission	1,134,251,182	58,974,846	46,644,788	821,895,602	123,997,369	19,394,860	-	-	-	-	-	-	-	-	-	-	63,343,717
	Distribution																	
24	Substations	44,549,497	-	-	-	-	44,549,497	-	-	-	-	-	-	-	-	-	-	-
25	Land & Land Improvements	3,384,051	-	-	-	-	-	2,551,406	325,038	-	295,935	211,672	-	-	-	-	-	-
26	Poles	160,253,236	-	-	-	-	-	92,682,138	31,674,373	-	16,404,803	19,491,922	-	-	-	-	-	-
27	Primary Conductor & Eqpt	25,812,930	-	-	-	-	-	22,896,069	2,916,861	-	-	-	-	-	-	-	-	-
28	Submarine Conductor	9,854,684	-	-	-	-	-	9,854,684	-	-	-	-	-	-	-	-	-	-
29	Transformers	29,563,425	-	-	-	-	-	-	10,672,397	18,891,029	-	-	-	-	-	-	-	-
30	Secondary Conductor&Eqpt	3,070,255	-	-	-	-	-	-	-	-	1,789,959	1,280,296	-	-	-	-	-	-
31	Services	6,162,249	-	-	-	-	-	-	-	-	-	6,162,249	-	-	-	-	-	-
32	Meters	9,766,093	-	-	-	-	-	-	-	-	-	-	9,766,093	-	-	-	-	-
33	Street Lighting	5,258,084	-	-	-	-	-	-	-	-	-	-	-	-	-	5,258,084	-	-
34	Subtotal Distribution	297,674,504	-	-	-	-	44,549,497	127,984,297	34,916,272	10,672,397	18,891,029	18,490,697	20,983,890	6,162,249	9,766,093	5,258,084	-	-
35	Subttl Prod, Trans, & Dist	3,203,063,241	1,217,778,563	658,978,625	821,895,602	123,997,369	63,944,357	127,984,297	34,916,272	10,672,397	18,891,029	18,490,697	20,983,890	6,162,249	9,766,093	5,258,084	-	63,343,717
36	General	233,673,560	109,613,189	38,726,936	47,661,908	6,622,265	4,454,820	8,401,746	2,292,138	700,608	1,240,134	1,213,853	1,377,523	404,531	1,239,177	345,176	7,543,899	1,835,657
37	NLSO	1,935,320	735,793	398,161	496,597	74,920	38,636	77,329	21,097	6,448	11,414	11,172	12,679	3,723	5,901	3,177	-	38,273
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Feasibility Studies	(180,127)	(180,127)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Software - General	13,917,263	5,291,230	2,863,253	3,571,124	538,767	277,837	556,090	151,711	46,371	82,081	80,342	91,175	26,775	42,434	22,846	-	275,228
42	Total Plant	3,452,409,258	1,333,238,649	700,966,975	873,625,231	131,233,322	68,715,650	137,019,463	37,381,217	11,425,824	20,224,658	19,796,065	22,465,267	6,597,278	11,053,604	5,629,283	7,543,899	65,492,875

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Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1	19
	Description	Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch F 4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch F 4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch F 4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch F 4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch F 4.1 L.1
6	Granite Canal	Production - Demand, Energy ratios Sch F 4.1 L.1
7	Exploits	Production - Demand, Energy ratios Sch F 4.1 L.1
8	Star Lake	Production - Demand, Energy ratios Sch F 4.1 L.1
9	Other Hydraulic	Production - Demand, Energy ratios Sch F 4.1 L.1, 2
10	Subtotal Hydraulic	
11	Holyrood	Production - Demand, Energy ratios Sch F 4.1 L.3
12	Gas Turbines	Production - Demand, Energy ratios Sch F 4.1 L.4
13	Roddickton	Production - Demand, Energy ratios Sch F 4.1 L.3
14	Diesel	Production - Demand, Energy ratios Sch F 4.1 L.5
15	Subtotal Production	
	Transmission	
16	Lines	Production - Demand, Energy ratios Sch F 4.1 L.17 Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
17	Terminal Stations	Production - Demand, Energy subtotals, L. 15; Transmission - Demand; Spec Assigned - Custmr
18	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch F 4.1 L.20
19	Term Stns - Holyrood	Production - Demand, Energy ratios Sch F 4.1 L.21
20	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch F 4.1 L.22, 23
21	Term Stns - Distribution	Distribution - Substations Demand
22	Subtotal Term Stns	
23	Subtotal Transmission	
	Distribution	
24	Substations	Production - Demand; Dist Substns - Demand
25	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.32
26	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.37
27	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.38
28	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.39
29	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch F 4.1 L.40
30	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.41
31	Services	Services Customer
32	Meters	Meters - Customer
33	Street Lighting	Street Lighting - Customer
34	Subtotal Distribution	
35	Subttl Prod, Trans, & Dist	
36	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch F 2.4 L.15, 16
37		
38	Telecontrol - Custmr & Spec	Specifically Assigned - Customer
39	Feasibility Studies	Production, Transmission - Demand
40	Feasibility Studies - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.35
41	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.35
42	Total Plant	

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Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned Customer
							Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
	Production Hydraulic																	
1	Bay D'Espoir	817,319,522	406,311,734	411,007,788	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	(308,183)	(153,206)	(154,977)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	2,850,569	1,417,096	1,433,474	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	(92,283)	(45,876)	(46,407)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	(34,788)	(17,294)	(17,494)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	(32,689)	(16,250)	(16,438)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Star Lake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other Small Hydraulic	264,354	131,418	132,937	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Subtotal Hydraulic	819,966,503	407,627,620	412,338,883	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Holyrood	146,045,381	129,746,716	16,298,665	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Turbines	126,292,246	126,292,246	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Diesel	5,172,218	5,172,218	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal Production Transmission	1,097,476,348	668,838,800	428,637,548	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Lines	417,821,974	9,064,399	9,169,164	351,254,883	34,898,171	-	-	-	-	-	-	-	-	-	-	-	13,435,358
17	Terminal Stations	251,981,802	-	-	221,893,580	16,264,106	-	-	-	-	-	-	-	-	-	-	-	13,824,115
18	Term Stns - Hydraulic	31,674,087	15,746,049	15,928,038	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Holyrood	8,652,255	7,686,664	965,592	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Gas Tur/Dsl	354,105	354,105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Term Stns - Distribution	11,523,736	-	-	-	-	11,523,736	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal Term Stns	304,185,986	23,786,818	16,893,630	221,893,580	16,264,106	11,523,736	-	-	-	-	-	-	-	-	-	-	13,824,115
23	Subtotal Trans & Term Stns Distribution	722,007,960	32,851,217	26,062,793	573,148,463	51,162,277	11,523,736	-	-	-	-	-	-	-	-	-	-	27,259,474
24	Substations	51,022,061	-	-	-	-	51,022,061	-	-	-	-	-	-	-	-	-	-	-
25	Land & Land Improvements	1,847,171	-	-	-	-	-	1,392,675	177,421	-	-	161,535	115,541	-	-	-	-	-
26	Poles	64,554,582	-	-	-	-	-	37,335,013	12,759,342	-	-	6,608,323	7,851,903	-	-	-	-	-
27	Primary Conductor & Eqpt	14,135,421	-	-	-	-	-	12,538,118	1,597,303	-	-	-	-	-	-	-	-	-
28	Submarine Conductor	1,560,642	-	-	-	-	-	1,560,642	-	-	-	-	-	-	-	-	-	-
29	Transformers	14,450,703	-	-	-	-	-	-	5,216,704	9,233,999	-	-	-	-	-	-	-	-
30	Secondary Conductor&Eqpt	899,951	-	-	-	-	-	-	-	-	524,671	375,280	-	-	-	-	-	-
31	Services	1,764,688	-	-	-	-	-	-	-	-	-	-	1,764,688	-	-	-	-	-
32	Meters	6,895,204	-	-	-	-	-	-	-	-	-	-	-	-	6,895,204	-	-	-
33	Street Lighting	2,172,511	-	-	-	-	-	-	-	-	-	-	-	-	-	2,172,511	-	-
34	Subtotal Distribution	159,302,933	-	-	-	-	51,022,061	52,826,448	14,534,065	5,216,704	9,233,999	7,294,530	8,342,723	1,764,688	6,895,204	2,172,511	-	-
35	Subttl Prod, Trans, & Dist	1,978,787,241	701,690,017	454,700,341	573,148,463	51,162,277	62,545,797	52,826,448	14,534,065	5,216,704	9,233,999	7,294,530	8,342,723	1,764,688	6,895,204	2,172,511	-	27,259,474
36	General	109,768,211	51,490,822	18,191,988	22,389,193	3,110,811	2,092,653	3,946,722	1,076,732	329,111	582,553	570,208	647,092	190,029	582,104	162,146	3,543,749	862,300
37	NLSO	596,295	211,450	137,021	172,715	15,417	18,848	15,919	4,380	1,572	2,783	2,198	2,514	532	2,078	655	-	8,214
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Feasibility Studies	(180,127)	(180,127)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Software - General	13,768,409	4,882,362	3,163,807	3,987,969	355,987	435,194	367,567	101,128	36,298	64,250	50,755	58,049	12,279	47,977	15,116	-	189,672
42	Total Net Book Value	2,102,740,030	758,094,524	476,193,156	599,698,339	54,644,492	65,092,492	57,156,656	15,716,306	5,583,684	9,883,585	7,917,691	9,050,378	1,967,527	7,527,362	2,350,429	3,543,749	28,319,660

		Functional Classification of Operating & Maintenance Expense																
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution		Line Transformers		Secondary Lines		Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Specifically Assigned Customer	
							Substations Demand	Primary Lines Demand	Demand	Customer	Demand	Customer						Demand
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	
1	Hydraulic	15,587,945	7,749,191	7,838,754	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Holyrood / Thermal	20,137,025	17,889,733	2,247,292	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Gas Turbine	4,183,851	4,183,851	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Diesel	322,873	322,873	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Other	715,584	468,186	247,398	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Subtotal Production	40,947,279	30,613,834	10,333,445	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
8	Transmission Lines	2,078,729	54,796	55,430	1,662,675	305,827	-	-	-	-	-	-	-	-	-	-	-	
9	Terminal Stations	5,948,514	549,183	386,018	4,058,593	392,439	252,670	-	-	-	-	-	-	-	-	-	309,611	
10	Other	10,784,474	581,624	460,022	8,105,734	1,222,892	191,277	-	-	-	-	-	-	-	-	-	222,924	
11	Subtotal Transmission	18,811,716	1,185,603	901,470	13,827,003	1,921,158	443,947	-	-	-	-	-	-	-	-	-	532,535	
Distribution																		
12	Other	5,483,071	-	-	-	-	848,423	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	-	100,138	-	
13	Meters	359,493	-	-	-	-	-	-	-	-	-	-	-	359,493	-	-	-	
14	Subtotal Distribution	5,842,563	-	-	-	-	848,423	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	359,493	100,138	-	
15	Subttl Prod, Trans, & Dist	65,601,559	31,799,438	11,234,914	13,827,003	1,921,158	1,292,370	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	359,493	100,138	-	
16	Customer Accounting	2,188,530	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,188,530	
Administrative & General:																		
Plant-Related:																		
17	Production	7,256,926	4,747,995	2,508,931	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Prod - Gas Turb & Diesel	2,043,182	2,043,182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Transmission	5,495,558	302,640	239,366	4,217,708	636,315	99,528	-	-	-	-	-	-	-	-	-	-	
20	Distribution	2,747,806	-	-	-	-	411,232	1,181,411	322,309	98,516	174,381	170,686	193,700	56,883	90,150	48,537	-	
21	Prod, Trans, Distn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Prod, Trans, Distn and General	280,720	110,504	58,099	72,409	10,877	5,695	11,357	3,098	947	1,676	1,641	1,862	547	916	467	625	
23	Hydraulic & Holyrood	630,854	108,620	18,601	327,748	49,447	25,499	51,036	13,924	4,256	7,533	7,374	8,368	2,457	3,894	2,097	-	
24	Property Insurance	2,927,026	1,546,264	803,125	424,143	43,418	80,700	9,998	2,728	834	1,476	1,445	1,639	481	1,468	411	8,896	
Revenue-Related:																		
25	Municipal Tax	1,436,329	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
26	PUB Assessment	977,601	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
27	All Expense-Related	28,306,854	13,383,508	4,728,466	5,819,405	808,563	543,923	1,025,833	279,865	85,543	151,417	148,209	168,192	49,392	151,301	42,145	921,092	
28	Prod, Trans, and Distn Expense-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	Related	525,392	256,761	90,715	111,644	15,512	10,435	19,680	5,369	1,641	2,905	2,843	3,227	948	2,903	809	-	
30	Subtotal Admin & General	52,628,248	22,499,474	8,447,303	10,973,058	1,564,132	1,177,013	2,299,317	627,292	191,736	339,389	332,197	376,988	110,709	250,632	94,465	930,613	
Total Operating & Maintenance Expenses																		
		120,418,337	54,298,912	19,682,217	24,800,061	3,485,290	2,469,383	4,736,713	1,292,255	394,987	699,159	684,343	776,616	228,066	610,124	194,602	3,119,143	
																	532,535	

NEWFOUNDLAND & LABRADOR HYDRO
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Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	Description	Revenue Related		Basis of Functional Classification
		Municipal Tax	PUB Assessment	
1	Production			
1	Hydraulic	-	-	Prorated on Hydraulic Plant in Service - Sch F 2.2 L.10
2	Holyrood / Thermal	-	-	Prorated on Holyrood Plant in Service - Sch F 2.2 L.11
3	Roddickton	-	-	Prorated on Roddickton Plant in Service - Sch F 2.2 L.13
4	Gas Turbine	-	-	Prorated on Gas Turbines Plant in Service - Sch F 2.2 L.12
5	Diesel	-	-	Prorated on Diesel Plant in Service - Sch F 2.2 L.14
6	Other	-	-	Prorated on Production Plant in Service - Sch F 2.2 L.15
7	Subtotal Production	-	-	
	Transmission			
8	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch F 2.2 L.16
9	Terminal Stations	-	-	Prorated on Terminal Stations Plant in Service - Sch F 2.2 L.22
10	Other	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.23
11	Subtotal Transmission	-	-	
	Distribution			
12	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch F 2.2 L. 34, less L. 32
13	Meters	-	-	Meters - Customer
14	Subtotal Distribution	-	-	
15	Subttl Prod, Trans, & Dist	-	-	
16	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
17	Production	-	-	Prorated on Production Plant in Service - Sch F 2.2 L.15
18	Prod - Gas Turb & Diesel	-	-	Prorated on Gas Turbine & Diesel Production Plant in Service - Sch F 2.2 L.12, 14
19	Transmission	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.23
20	Distribution	-	-	Prorated on Distribution Plant in Service - Sch F 2.2 L.34
21	Prod, Trans, Distn	-	-	Prorated on Prod, Trans & Distribution Plant in Service - Sch F 2.2 L.35
22	Plant	-	-	Prorated on Total Plant in Service, Sch F 2.2, L. 42
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	-	-	Prorated on Total Plant in Service, Sch F 2.2, L. 35 Less L. 10 and L. 11
24	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch F 2.2 L.15, 22, 24, 36 - 38
	Revenue-Related:			
25	Municipal Tax	1,436,329	-	Revenue-related
26	PUB Assessment	-	977,601	Revenue-related
27	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 15, 16
28	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L 15
29	Subtotal Admin & General	1,436,329	977,601	
30	Total Operating & Maintenance Expenses	1,436,329	977,601	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
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		Functional Classification of Depreciation Expense																
1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution		Line Transformers		Secondary Lines		Services		Meters	Street Lighting	Accounting	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Primary Lines Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	
Production Hydraulic																		
1	Bay D'Espoir	18,997,665	9,444,255	9,553,410	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	14,735	7,325	7,410	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	30,668	15,246	15,422	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	5,515	2,741	2,773	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	172	85	86	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	11,636	5,785	5,851	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Muskrat Falls Sustaining	720,638	358,249	362,389	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other Small Hydraulic	3,222	1,602	1,620	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Subtotal Hydraulic	19,784,250	9,835,288	9,948,962	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Holyrood	31,706,547	28,168,096	3,538,451	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Turbines	5,751,897	5,751,897	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Diesel	200,824	200,824	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal Production	57,443,518	43,956,105	13,487,413	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																		
16	Lines	10,711,225	303,276	306,781	8,146,139	1,411,968	-	-	-	-	-	-	-	-	-	-	-	543,062
17	Terminal Stations	7,749,078	-	-	6,810,065	568,684	-	-	-	-	-	-	-	-	-	-	-	370,329
18	Term Stns - Hydraulic	930,929	462,790	468,139	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Holyrood	396,428	352,187	44,241	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Gas Tur/Dsl	9,923	9,923	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Term Stns - Distribution	381,353	-	-	-	-	381,353	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal Term Stns	9,467,711	824,900	512,380	6,810,065	568,684	381,353	-	-	-	-	-	-	-	-	-	-	370,329
23	Subtotal Transmission	20,178,936	1,128,176	819,161	14,956,204	1,980,652	381,353	-	-	-	-	-	-	-	-	-	-	913,390
Distribution																		
24	Substations	1,291,292	-	-	-	-	1,291,292	-	-	-	-	-	-	-	-	-	-	-
25	Land & Land Improvements	43,713	-	-	-	-	-	32,958	4,199	-	-	3,823	2,734	-	-	-	-	-
26	Poles	4,179,458	-	-	-	-	-	2,417,181	826,078	-	-	427,843	508,356	-	-	-	-	-
27	Primary Conductor & Eqpt	547,959	-	-	-	-	-	486,039	61,919	-	-	-	-	-	-	-	-	-
28	Submarine Conductor	178,060	-	-	-	-	-	178,060	-	-	-	-	-	-	-	-	-	-
29	Transformers	761,905	-	-	-	-	-	-	275,048	486,857	-	-	-	-	-	-	-	-
30	Secondary Conductor&Eqpt	42,305	-	-	-	-	-	-	-	-	24,664	17,641	-	-	-	-	-	-
31	Services	116,962	-	-	-	-	-	-	-	-	-	-	116,962	-	-	-	-	-
32	Meters	516,551	-	-	-	-	-	-	-	-	-	-	-	-	516,551	-	-	-
33	Street Lighting	207,811	-	-	-	-	-	-	-	-	-	-	-	-	-	-	207,811	-
34	Subtotal Distribution	7,886,016	-	-	-	-	1,291,292	3,114,238	892,196	275,048	486,857	456,329	528,731	116,962	516,551	207,811	-	-
35	Subttl Prod, Trans, & Dist	85,508,470	45,084,281	14,306,574	14,956,204	1,980,652	1,672,645	3,114,238	892,196	275,048	486,857	456,329	528,731	116,962	516,551	207,811	-	913,390
36	General	11,618,932	5,450,288	1,925,616	2,369,889	329,278	221,507	417,759	113,972	34,836	61,663	60,356	68,494	20,114	61,615	17,163	375,105	91,274
37	NLSO	10,963	5,780	1,834	1,917	254	214	399	114	35	62	59	68	15	66	27	-	117
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	GEC and AFUDC	383,174	202,028	64,110	67,021	8,876	7,495	13,955	3,998	1,233	2,182	2,045	2,369	524	2,315	931	-	4,093
41	Software - General	2,990,596	1,576,789	500,362	523,082	69,272	58,500	108,918	31,204	9,620	17,027	15,960	18,492	4,091	18,066	7,268	-	31,945
42	Total Depreciation Expense	100,512,135	52,319,167	16,798,496	17,918,114	2,388,332	1,960,361	3,655,270	1,041,484	320,771	567,792	534,749	618,155	141,706	598,613	233,200	375,105	1,040,820

NEWFOUNDLAND AND LABRADOR HYDRO
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Island Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution	Primary Lines Demand (\$)	Customer (\$)	Line Transformers Demand (\$)	Customer (\$)	Secondary Lines Demand (\$)	Customer (\$)	Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)											
1	Average Net Book Value	2,102,740,030	758,094,524	476,193,156	599,698,339	54,644,492	65,092,492	57,156,656	15,716,306	5,583,684	9,883,585	7,917,691	9,050,378	1,967,527	7,527,362	2,350,429	3,543,749	28,319,660
2	Cash Working Capital (Including Muskrat Falls)	116,490,187	41,997,856	26,380,736	33,222,829	3,027,263	3,606,074	3,166,435	870,671	309,332	547,543	438,634	501,384	108,999	417,010	130,212	196,321	1,568,887
3	Fuel Inventory - No. 6 Fuel	53,963,965	-	53,963,965	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	180,546	180,546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	7,763,006	7,763,006	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	39,481,123	15,246,674	8,016,131	9,990,619	1,500,760	785,820	1,566,930	427,485	130,664	231,286	226,384	256,909	75,445	126,407	64,375	86,271	748,965
7	Deferred Charges: Muskrat Falls	47,775	42,443	5,332	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Deffered Charges: Foreign Exchange Loss and																	
8	Regulatory Costs	101,068,768	36,438,018	22,888,353	28,824,663	2,626,502	3,128,688	2,747,250	755,408	268,381	475,057	380,566	435,009	94,570	361,805	112,974	170,331	1,361,192
9	Retired Asset Pool	28,866,724	10,407,233	6,537,250	8,232,747	750,168	893,599	784,655	215,756	76,654	135,683	108,695	124,245	27,010	103,337	32,267	48,649	388,776
10	Total Rate Base	2,450,602,123	870,170,300	593,984,922	679,969,197	62,549,186	73,506,673	65,421,926	17,985,626	6,368,715	11,273,154	9,071,971	10,367,924	2,273,552	8,535,921	2,690,257	4,045,320	32,387,481
11	Less: Rural Asset Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate Base Available for Equity Return	2,450,602,123	870,170,300	593,984,922	679,969,197	62,549,186	73,506,673	65,421,926	17,985,626	6,368,715	11,273,154	9,071,971	10,367,924	2,273,552	8,535,921	2,690,257	4,045,320	32,387,481
13	Return on Debt	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863
14	Return on Equity	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646
15	Return on Rate Base	119,589,384	42,464,311	28,986,464	33,182,497	3,052,400	3,587,126	3,192,590	877,699	310,793	550,130	442,712	505,955	110,949	416,553	131,285	197,412	1,580,509

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	19 Basis of Functional Classification
1	Average Net Book Value	Sch F 2.3 , L. 42
2	Cash Working Capital (Including Muskrat F: Prorated on Average Net Book Value, L. 1	
3	Fuel Inventory - No. 6 Fuel	Production - Demand, Energy ratios Sch F 4.1 L.10
4	Fuel Inventory - Diesel	Production - Demand, Energy ratios Sch F 4.1 L.12
5	Fuel Inventory - Gas Turbine	Production - Demand, Energy ratios Sch F 4.1 L.11
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch F 2.2, L. 42
7	Deferred Charges: Muskrat Falls Deferred Charges: Foreign Exchange Loss and	Production - Demand, Energy ratios Sch F 4.1 L.3
8	Regulatory Costs	Prorated on Average Net Book Value, L. 1
9	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
10	Total Rate Base	
11	Less: Rural Asset Portion	N/A
12	Rate Base Available for Equity Return	
13	Return on Debt	L.10 x Sch F 1.1,p2,L.16
14	Return on Equity	L.12 x Sch F 1.1,p2,L.19
15	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand (1 CP kW)	Production Energy (MWh @ Gen)	Transmission Demand (CP kW)	Rural Prod & Transmission Demand (CP kW)	Distribution	Primary Lines		Line Transformers		Secondary Lines		Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Specifically Assigned Customer
							Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer					
							(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)					
Amounts																		
1	Newfoundland Power	-	1,459,198	6,292,250	1,435,869	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	81,911	641,688	78,487	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																		
4	1.1 Domestic	-	33,033	123,930	31,652	31,652	29,317	29,317	11,494	25,936	11,494	25,936	11,494	11,494	11,494	-	11,494	-
5	1.12 Domestic All Electric	-	38,341	167,083	36,739	36,739	34,028	34,028	8,714	30,104	8,714	30,104	8,714	8,714	8,714	-	8,714	-
6	1.3 Special	-	133	393	127	127	118	118	1	104	1	104	1	1	1	-	1	-
7	2.1 GS 0-10 kW	-	15,207	82,954	14,571	14,571	13,496	13,496	3,042	11,940	3,042	11,940	3,042	14,508	14,508	-	3,042	-
8	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.3 GS 110-1,000 kVa	-	10,056	61,765	9,636	9,636	8,925	8,925	84	7,321	84	7,321	84	703	703	-	84	-
10	2.4 GS Over 1,000 kVa	-	5,870	44,445	5,625	5,625	5,210	5,210	8	1,902	8	1,902	8	67	67	-	8	-
11	4.1 Street and Area Lighting	-	629	2,365	603	603	558	558	1,057	494	1,057	494	1,057	-	-	1	1,057	-
12	Subtotal Rural	-	103,269	482,936	98,953	98,953	91,651	91,651	24,398	77,803	24,398	77,803	24,398	35,487	35,487	1	24,398	-
13	Total	-	1,644,378	7,416,874	1,613,309	98,953	91,651	91,651	24,398	77,803	24,398	77,803	24,398	35,487	35,487	1	24,398	-
Ratios Excluding Return on Equity																		
14	Newfoundland Power	-	0.8874	0.8484	0.8900	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.0498	0.0865	0.0486	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																		
17	1.1 Domestic	-	0.0201	0.0167	0.0196	0.3199	0.3199	0.3199	0.4711	0.3334	0.4711	0.3334	0.4711	0.3239	0.3239	-	0.4711	-
18	1.12 Domestic All Electric	-	0.0233	0.0225	0.0228	0.3713	0.3713	0.3713	0.3571	0.3869	0.3571	0.3869	0.3571	0.2455	0.2455	-	0.3571	-
19	1.3 Special	-	0.0001	0.0001	0.0001	0.0013	0.0013	0.0013	0.0000	0.0013	0.0000	0.0013	0.0000	0.0000	0.0000	-	0.0000	-
20	2.1 GS 0-10 kW	-	0.0092	0.0112	0.0090	0.1473	0.1473	0.1473	0.1247	0.1535	0.1247	0.1535	0.1247	0.4088	0.4088	-	0.1247	-
21	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	2.3 GS 110-1,000 kVa	-	0.0061	0.0083	0.0060	0.0974	0.0974	0.0974	0.0034	0.0941	0.0034	0.0941	0.0034	0.0198	0.0198	-	0.0034	-
23	2.4 GS Over 1,000 kVa	-	0.0036	0.0060	0.0035	0.0568	0.0568	0.0568	0.0003	0.0245	0.0003	0.0245	0.0003	0.0019	0.0019	-	0.0003	-
24	4.1 Street and Area Lighting	-	0.0004	0.0003	0.0004	0.0061	0.0061	0.0061	0.0433	0.0063	0.0433	0.0063	0.0433	-	-	1.0000	0.0433	-
25	Subtotal Rural	-	0.0628	0.0651	0.0613	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
26	Total	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related		20
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)	
	Amounts			
1	Newfoundland Power	-	484,507,755	
2	Industrial - Firm	-	43,914,366	
3	Industrial - Non-Firm	-	-	
	Rural			
4	1.1 Domestic	13,704,053	13,704,053	
5	1.12 Domestic All Electric	17,350,913	17,350,913	
6	1.3 Special	19,223	19,223	
7	2.1 GS 0-10 kW	9,465,475	9,465,475	
8	2.2 GS 10-100 kW	-	-	
9	2.3 GS 110-1,000 kVa	6,141,548	6,141,548	
10	2.4 GS Over 1,000 kVa	3,400,344	3,400,344	
11	4.1 Street and Area Lighting	993,685	993,685	
12	Subtotal Rural	51,075,241	51,075,241	
13	Total	51,075,241	579,497,362	
	Ratios Excluding Return on Equity			
14	Newfoundland Power	-	0.8361	
15	Industrial - Firm	-	0.0758	
16	Industrial - Non-Firm	-	-	
	Rural			
17	1.1 Domestic	0.2683	0.0236	
18	1.12 Domestic All Electric	0.3397	0.0299	
19	1.3 Special	0.0004	0.0000	
20	2.1 GS 0-10 kW	0.1853	0.0163	
21	2.2 GS 10-100 kW	-	-	
22	2.3 GS 110-1,000 kVa	0.1202	0.0106	
23	2.4 GS Over 1,000 kVa	0.0666	0.0059	
24	4.1 Street and Area Lighting	0.0195	0.0017	
25	Subtotal Rural	1.0000	0.0881	
26	Total	1.0000	1.0000	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected

Line No.	Description	1	2	3	4	5	6	Allocation of Functionalized Amounts to Classes of Service										17	18
								Rural Prod & Transmission Demand (\$)	Distribution		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
									Substations Demand (\$)	Primary Lines Demand (\$)	Customer Demand (\$)	Customer Demand (\$)	Customer Demand (\$)	Customer Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Allocated Rev Reqmt Excl Return																		
1	Newfoundland Power	480,816,112	238,369,120	202,361,150	37,946,237	-	-	-	-	-	-	-	-	-	-	-	-	-	1,324,923
2	Industrial - Firm	36,412,158	13,380,603	20,636,934	2,074,210	-	-	-	-	-	-	-	-	-	-	-	-	-	246,571
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																		
4	1.1 Domestic	21,598,403	5,396,131	3,985,645	836,488	2,182,159	1,414,326	2,457,945	985,978	238,168	595,767	364,803	587,292	119,519	390,844	-	1,636,173	-	-
5	1.12 Domestic All Electric	24,122,131	6,263,307	5,373,459	970,914	2,532,839	1,641,613	2,852,945	747,476	276,443	451,655	423,428	445,230	90,608	296,301	-	1,240,394	-	-
6	1.3 Special	65,432	21,705	12,636	3,365	8,777	5,689	9,887	86	958	52	1,467	51	10	34	-	142	-	-
7	2.1 GS 0-10 kW	10,534,147	2,484,114	2,667,840	385,078	1,004,559	651,086	1,131,517	260,908	109,641	157,651	167,937	155,408	150,865	493,348	-	432,962	-	-
8	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.3 GS 110-1,000 kVa	6,138,406	1,642,711	1,986,392	254,647	664,301	430,555	748,257	7,163	67,231	4,328	102,978	4,267	7,310	23,906	-	11,886	-	-
10	2.4 GS Over 1,000 kVa	3,763,791	958,948	1,429,363	148,652	387,792	251,340	436,802	686	17,469	415	26,757	409	700	2,290	-	1,139	-	-
11	4.1 Street and Area Lighting	1,128,028	102,778	76,069	15,932	41,563	26,938	46,815	90,629	4,536	54,762	6,948	53,983	-	-	427,156	150,394	-	-
12	Subtotal Rural	67,350,337	16,869,693	15,531,404	2,615,076	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	-	-
13	Total	584,578,607	268,619,415	238,529,488	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495	-
	Allocated Return on Debt																		
14	Newfoundland Power	57,498,958	23,242,527	15,167,953	18,215,993	-	-	-	-	-	-	-	-	-	-	-	-	-	872,485
15	Industrial - Firm	3,949,632	1,304,695	1,546,839	995,719	-	-	-	-	-	-	-	-	-	-	-	-	-	102,379
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																		
17	1.1 Domestic	4,045,899	526,158	298,743	401,554	602,231	707,732	629,891	255,038	63,905	159,855	91,030	147,018	22,165	83,217	-	57,363	-	-
18	1.12 Domestic All Electric	4,460,358	610,713	402,767	466,085	699,012	821,466	731,116	193,346	74,174	121,187	105,658	111,456	16,803	63,087	-	43,487	-	-
19	1.3 Special	13,168	2,116	947	1,615	2,422	2,847	2,534	22	257	14	366	13	2	7	-	5	-	-
20	2.1 GS 0-10 kW	1,888,269	242,217	199,968	184,856	277,238	325,805	289,971	67,488	29,419	42,301	41,906	38,904	27,978	105,042	-	15,179	-	-
21	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	2.3 GS 110-1,000 kVa	1,076,525	160,175	148,890	122,243	183,334	215,450	191,754	1,853	18,039	1,161	25,696	1,068	1,356	5,090	-	417	-	-
23	2.4 GS Over 1,000 kVa	629,146	93,504	107,138	71,360	107,023	125,771	111,938	178	4,687	111	6,677	102	130	488	-	40	-	-
24	4.1 Street and Area Lighting	201,169	10,022	5,702	7,648	11,470	13,480	11,997	23,443	1,217	14,694	1,734	13,514	-	-	80,977	5,273	-	-
25	Subtotal Rural	12,314,534	1,644,904	1,164,154	1,255,360	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	-	-
26	Total	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863	-
	Allocated Return on Equity																		
27	Newfoundland Power	35,721,944	14,439,709	9,423,280	11,316,913	-	-	-	-	-	-	-	-	-	-	-	-	-	542,042
28	Industrial - Firm	2,453,758	810,558	960,993	618,603	-	-	-	-	-	-	-	-	-	-	-	-	-	63,604
29	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																		
30	1.1 Domestic	2,513,565	326,882	185,598	249,470	374,144	439,687	391,327	158,446	39,702	99,312	56,553	91,337	13,770	51,700	-	35,638	-	-
31	1.12 Domestic All Electric	2,771,053	379,413	250,224	289,561	434,270	510,346	454,215	120,119	46,082	75,289	65,642	69,243	10,439	39,194	-	27,017	-	-
32	1.3 Special	8,181	1,315	588	1,003	1,505	1,769	1,574	14	160	9	227	8	1	4	-	3	-	-
33	2.1 GS 0-10 kW	1,173,111	150,480	124,232	114,844	172,237	202,410	180,148	41,928	18,277	26,280	26,034	24,169	17,382	65,259	-	9,430	-	-
34	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	2.3 GS 110-1,000 kVa	668,805	99,511	92,500	75,945	113,898	133,851	119,129	1,151	11,207	721	15,964	664	842	3,162	-	259	-	-
36	2.4 GS Over 1,000 kVa	390,865	58,090	66,561	44,333	66,489	78,137	69,543	110	2,912	69	4,148	64	81	303	-	25	-	-
37	4.1 Street and Area Lighting	124,979	6,226	3,542	4,752	7,126	8,375	7,453	14,564	756	9,129	1,077	8,396	-	-	50,308	3,276	-	-
38	Subtotal Rural	7,650,558	1,021,917	723,245	779,908	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	-	-
39	Total	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	19	20
		Revenue Related	
		Municipal Tax	PUB Assessment (\$)
1	Allocated Rev Reqmt Excl Return		
1	Newfoundland Power	-	814,682
2	Industrial - Firm	-	73,840
3	Industrial - Non-Firm	-	-
4	Rural		
4	1.1 Domestic	384,123	23,043
5	1.12 Domestic All Electric	486,344	29,175
6	1.3 Special	539	32
7	2.1 GS 0-10 kW	265,316	15,916
8	2.2 GS 10-100 kW	-	-
9	2.3 GS 110-1,000 kVa	172,147	10,327
10	2.4 GS Over 1,000 kVa	95,311	5,718
11	4.1 Street and Area Lighting	27,853	1,671
12	Subtotal Rural	1,431,632	85,881
13	Total	1,431,632	974,404
14	Allocated Return on Debt		
14	Newfoundland Power	-	-
15	Industrial - Firm	-	-
16	Industrial - Non-Firm	-	-
17	Rural		
17	1.1 Domestic	-	-
18	1.12 Domestic All Electric	-	-
19	1.3 Special	-	-
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	-	-
22	2.3 GS 110-1,000 kVa	-	-
23	2.4 GS Over 1,000 kVa	-	-
24	4.1 Street and Area Lighting	-	-
25	Subtotal Rural	-	-
26	Total	-	-
27	Allocated Return on Equity		
27	Newfoundland Power	-	-
28	Industrial - Firm	-	-
29	Industrial - Non-Firm	-	-
30	Rural		
30	1.1 Domestic	-	-
31	1.12 Domestic All Electric	-	-
32	1.3 Special	-	-
33	2.1 GS 0-10 kW	-	-
34	2.2 GS 10-100 kW	-	-
35	2.3 GS 110-1,000 kVa	-	-
36	2.4 GS Over 1,000 kVa	-	-
37	4.1 Street and Area Lighting	-	-
38	Subtotal Rural	-	-
39	Total	-	-

NEWFOUNDLAND AND LABRADOR HYDRO

2027 Test Year Cost of Service Study

Island Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution		Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Services (\$)	Meters (\$)	Street Lighting (\$)	Accounting (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Primary Lines Demand (\$)										
40	Newfoundland Power	574,037,014	276,051,356	226,952,383	67,479,142	-	-	-	-	-	-	-	-	-	-	-	-	2,739,450
41	Industrial - Firm	42,815,548	15,495,856	23,144,765	3,688,533	-	-	-	-	-	-	-	-	-	-	-	-	412,554
42	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	28,157,867	6,249,170	4,469,987	1,487,512	3,158,534	2,561,745	3,479,163	1,399,461	341,774	854,933	512,386	825,647	155,455	525,761	-	1,729,173	-
44	1.12 Domestic All Electric	31,353,543	7,253,433	6,026,450	1,726,560	3,666,121	2,973,426	4,038,276	1,060,941	396,699	648,130	594,728	625,929	117,851	398,583	-	1,310,898	-
45	1.3 Special	86,780	25,136	14,172	5,983	12,705	10,304	13,994	122	1,375	74	2,061	72	14	46	-	150	-
46	2.1 GS 0-10 kW	13,595,527	2,876,811	2,992,040	684,777	1,454,034	1,179,302	1,601,636	370,324	157,336	226,231	235,877	218,482	196,225	663,649	-	457,572	-
47	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2.3 GS 110-1,000 kVa	7,883,736	1,902,397	2,227,781	452,834	961,533	779,856	1,059,140	10,167	96,478	6,211	144,639	5,998	9,508	32,158	-	12,562	-
49	2.4 GS Over 1,000 kVa	4,783,802	1,110,542	1,603,061	264,346	561,304	455,248	618,283	974	25,068	595	37,582	575	911	3,081	-	1,204	-
50	4.1 Street and Area Lighting	1,454,176	119,025	85,313	28,332	60,159	48,792	66,266	128,636	6,510	78,584	9,759	75,892	-	-	558,441	158,943	-
51	Subtotal Rural	87,315,429	19,536,514	17,418,804	4,650,345	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	-
52	Total	704,167,991	311,083,726	267,515,952	75,818,020	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	3,152,004
	Re-classification of Revenue-Related																	
53	Newfoundland Power	-	392,333	322,552	95,904	-	-	-	-	-	-	-	-	-	-	-	-	3,893
54	Industrial - Firm	-	26,771	39,985	6,372	-	-	-	-	-	-	-	-	-	-	-	-	713
55	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
56	1.1 Domestic	(0)	91,689	65,585	21,825	46,343	37,587	51,047	20,533	5,015	12,544	7,518	12,114	2,281	7,714	-	25,371	-
57	1.12 Domestic All Electric	0	121,255	100,744	28,863	61,286	49,707	67,508	17,736	6,632	10,835	9,942	10,464	1,970	6,663	-	21,914	-
58	1.3 Special	-	167	94	40	84	68	93	1	9	0	14	0	0	0	-	1	-
59	2.1 GS 0-10 kW	0	60,766	63,199	14,464	30,713	24,910	33,831	7,822	3,323	4,779	4,982	4,615	4,145	14,018	-	9,665	-
60	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	2.3 GS 110-1,000 kVa	(0)	45,075	52,785	10,729	22,783	18,478	25,095	241	2,286	147	3,427	142	225	762	-	298	-
62	2.4 GS Over 1,000 kVa	(0)	23,959	34,585	5,703	12,110	9,822	13,339	21	541	13	811	12	20	66	-	26	-
63	4.1 Street and Area Lighting	-	2,467	1,768	587	1,247	1,011	1,373	2,666	135	1,629	202	1,573	-	-	11,573	3,294	-
64	Subtotal Rural	(0)	345,378	318,760	82,212	174,565	141,582	192,286	49,020	17,940	29,946	26,896	28,920	8,641	29,224	11,573	60,569	-
65	Total	(0)	764,482	681,297	184,487	174,565	141,582	192,286	49,020	17,940	29,946	26,896	28,920	8,641	29,224	11,573	60,569	4,606
	Total Allocated Revenue Requirement																	
66	Newfoundland Power	574,037,014	276,443,689	227,274,935	67,575,046	-	-	-	-	-	-	-	-	-	-	-	-	2,743,343
67	Industrial - Firm	42,815,548	15,522,626	23,184,750	3,694,905	-	-	-	-	-	-	-	-	-	-	-	-	413,266
68	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
69	1.1 Domestic	28,157,867	6,340,860	4,535,571	1,509,337	3,204,877	2,599,331	3,530,210	1,419,995	346,789	867,477	519,904	837,762	157,735	533,475	-	1,754,544	-
70	1.12 Domestic All Electric	31,353,543	7,374,688	6,127,194	1,755,423	3,727,408	3,023,133	4,105,784	1,078,677	403,330	658,965	604,670	636,392	119,821	405,246	-	1,332,812	-
71	1.3 Special	86,780	25,303	14,266	6,023	12,789	10,373	14,087	123	1,384	75	2,075	72	14	46	-	151	-
72	2.1 GS 0-10 kW	13,595,527	2,937,577	3,055,240	699,242	1,484,747	1,204,211	1,635,466	378,146	160,660	231,010	240,860	223,097	200,369	677,667	-	467,237	-
73	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	2.3 GS 110-1,000 kVa	7,883,736	1,947,472	2,280,566	463,564	984,316	798,334	1,084,235	10,408	98,764	6,358	148,066	6,140	9,734	32,920	-	12,860	-
75	2.4 GS Over 1,000 kVa	4,783,802	1,134,501	1,637,646	270,049	573,414	465,070	631,622	995	25,609	608	38,393	587	931	3,147	-	1,230	-
76	4.1 Street and Area Lighting	1,454,176	121,492	87,081	28,919	61,406	49,804	67,639	131,302	6,645	80,213	9,961	77,465	-	-	570,014	162,237	-
77	Subtotal Rural	87,315,429	19,881,892	17,737,564	4,732,556	10,048,956	8,150,256	11,069,044	3,019,644	1,043,180	1,844,705	1,563,928	1,781,515	488,604	1,652,501	570,014	3,731,070	-
78	Total	704,167,991	311,848,208	268,197,249	76,002,507	10,048,956	8,150,256	11,069,044	3,019,644	1,043,180	1,844,705	1,563,928	1,781,515	488,604	1,652,501	570,014	3,731,070	3,156,610

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

		19	20	
		Revenue Related		
Line No.	Description	Municipal Tax (\$)	PUB Assessment (\$)	Basis of Proration
	Total Revenue Requirement			
40	Newfoundland Power	-	814,682	
41	Industrial - Firm	-	73,840	
42	Industrial - Non-Firm	-	-	
	Rural			
43	1.1 Domestic	384,123	23,043	
44	1.12 Domestic All Electric	486,344	29,175	
45	1.3 Special	539	32	
46	2.1 GS 0-10 kW	265,316	15,916	
47	2.2 GS 10-100 kW	-	-	
48	2.3 GS 110-1,000 kVa	172,147	10,327	
49	2.4 GS Over 1,000 kVa	95,311	5,718	
50	4.1 Street and Area Lighting	27,853	1,671	
51	Subtotal Rural	1,431,632	85,881	
52	Total	1,431,632	974,404	
	Re-classification of Revenue-Related			
53	Newfoundland Power	-	(814,682)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
54	Industrial - Firm	-	(73,840)	
55	Industrial - Non-Firm	-	-	
	Rural			
56	1.1 Domestic	(384,123)	(23,043)	
57	1.12 Domestic All Electric	(486,344)	(29,175)	
58	1.3 Special	(539)	(32)	
59	2.1 GS 0-10 kW	(265,316)	(15,916)	
60	2.2 GS 10-100 kW	-	-	
61	2.3 GS 110-1,000 kVa	(172,147)	(10,327)	
62	2.4 GS Over 1,000 kVa	(95,311)	(5,718)	
63	4.1 Street and Area Lighting	(27,853)	(1,671)	
64	Subtotal Rural	(1,431,632)	(85,881)	
65	Total	(1,431,632)	(974,404)	
	Total Allocated Revenue Requirement			
66	Newfoundland Power	-	-	
67	Industrial - Firm	-	-	
68	Industrial - Non-Firm	-	-	
	Rural			
69	1.1 Domestic	-	-	
70	1.12 Domestic All Electric	-	-	
71	1.3 Special	-	-	
72	2.1 GS 0-10 kW	-	-	
73	2.2 GS 10-100 kW	-	-	
74	2.3 GS 110-1,000 kVa	-	-	
75	2.4 GS Over 1,000 kVa	-	-	
76	4.1 Street and Area Lighting	-	-	
77	Subtotal Rural	-	-	
78	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Interconnected

Allocation of Specifically Assigned Amounts to Classes of Service

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	
Line No.	Description	Total Amount (\$)	OM&A				Depreciation				Expense Credits		Gains/Losses (\$) (NBV)	Subtotal Excluding Return (\$)	Return on Debt (\$) (NBV)	Return on Equity (\$) (NBV)	Subtotal Excl Rev Related (\$)	Revenue Related (\$)
			Lines (\$) (Plant)	Terminals (Plant)	General (\$) (C3 & C4)	Other (\$) (C3 & C4)	Lines (\$) (Direct)	Terminals (\$) (Direct)	Telecontrol & Feasibility Study (\$) (Direct)	General (\$) (Exp C3,4,6)	Rental Income (\$) (Plant)	Other (\$) (C6)						
Basis of Allocation - Amounts																		
1	Newfoundland Power Industrial		28,117,625	14,054,941	42,172,565	42,172,565	-	-	-	391,617	42,172,565	42,172,565	24,396,729	-	24,396,729	24,396,729	-	-
2	Vale		668,081	3,422,177	4,090,259	4,090,259	-	-	-	86,509	4,090,259	4,090,259	2,197,177	-	2,197,177	2,197,177	-	-
3	Corner Brook P & P - CB		-	16,570	16,570	16,570	-	-	-	3,679	16,570	16,570	(4,394)	-	(4,394)	(4,394)	-	-
4	Corner Brook P & P - DL		-	56,030	56,030	56,030	-	-	-	-	56,030	56,030	11,326	-	11,326	11,326	-	-
5	North Atlantic Refining Limited		-	1,820,569	1,820,569	1,820,569	-	-	-	34,958	1,820,569	1,820,569	658,707	-	658,707	658,707	-	-
6	Teck Resources		4,534,363	947,903	5,482,265	5,482,265	-	-	-	8,049	5,482,265	5,482,265	(72)	-	(72)	(72)	-	-
7	Marathon Gold		7,347,720	2,357,740	9,705,459	9,705,459	-	-	-	7,723	9,705,459	9,705,459	0	-	0	0	-	-
8	Subtotal Industrial		12,550,164	8,620,989	21,171,152	21,171,152	-	-	-	140,918	21,171,152	21,171,152	2,862,745	-	2,862,745	2,862,745	-	-
9	Total		40,667,788	22,675,929	63,343,717	63,343,717	-	-	-	532,535	63,343,717	63,343,717	27,259,474	-	27,259,474	27,259,474	-	-
Basis of Allocation - Ratios																		
11	Newfoundland Power Industrial		0.6914	0.6198	0.6658	0.6658	-	-	-	0.7354	0.6658	0.6658	0.8950	-	0.8950	0.8950	-	-
12	Vale		0.0164	0.1509	0.0646	0.0646	-	-	-	0.1624	0.0646	0.0646	0.0806	-	0.0806	0.0806	-	-
13	Corner Brook P & P - CB		-	0.0007	0.0003	0.0003	-	-	-	0.0069	0.0003	0.0003	(0.0002)	-	(0.0002)	(0.0002)	-	-
14	Corner Brook P & P - DL		-	0.0025	0.0009	0.0009	-	-	-	-	0.0009	0.0009	0.0004	-	0.0004	0.0004	-	-
15	North Atlantic Refining Ltd.		-	0.0803	0.0287	0.0287	-	-	-	0.0656	0.0287	0.0287	0.0242	-	0.0242	0.0242	-	-
16	Teck Resources		0.1115	0.0418	0.0865	0.0865	-	-	-	0.0151	0.0865	0.0865	(0.0000)	-	(0.0000)	(0.0000)	-	-
17	Marathon Gold		0.1807	0.1040	0.1532	0.1532	-	-	-	0.0145	0.1532	0.1532	0.0000	-	0.0000	0.0000	-	-
18	Subtotal Industrial		0.3086	0.3802	0.3342	0.3342	-	-	-	0.2646	0.3342	0.3342	0.1050	-	0.1050	0.1050	-	-
19	Total		1.0000	1.0000	1.0000	1.0000	-	-	-	1.0000	1.0000	1.0000	1.0000	-	1.0000	1.0000	-	-
Amounts Allocated																		
20	Newfoundland Power Industrial	2,743,343	-	227,683	-	163,934	536,015	304,821	-	93,709	(79)	(1,160)	-	1,324,923	872,485	542,042	2,739,450	3,893
21	Vale	285,041	-	50,296	-	36,214	7,047	43,021	-	20,701	(8)	(112)	-	157,157	78,576	48,816	284,550	492
22	Corner Brook P & P - CB	4,560	-	2,139	-	1,540	-	247	-	880	(0)	(0)	-	4,807	(157)	(98)	4,552	8
23	Corner Brook P & P - DL	1,262	-	-	-	-	-	605	-	-	(0)	(2)	-	603	405	252	1,260	2
24	North Atlantic Refining Ltd.	103,152	-	20,324	-	14,634	-	21,512	-	8,365	(3)	(50)	-	64,782	23,557	14,635	102,974	178
25	Teck Resources	9,950	-	4,679	-	3,369	-	123	-	1,926	(10)	(151)	-	9,937	(3)	(2)	9,933	17
26	Marathon Gold	9,302	-	4,490	-	3,233	(0)	-	-	1,848	(18)	(267)	-	9,286	0	0	9,286	16
27	Subtotal Industrial	413,266	-	81,929	-	58,990	7,047	65,508	-	33,720	(40)	(582)	-	246,571	102,379	63,604	412,554	713
28	Total	3,156,610	-	309,611	-	222,924	543,062	370,329	-	127,430	(119)	(1,742)	-	1,571,495	974,863	605,646	3,152,004	4,606

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Expenses																
1	Operating & Maintenance	12,671,431	1,006,216	50,059	4,679,099	784,698	1,450,041	416,403	326,508	577,947	229,782	256,167	87,963	286,694	96,441	1,787,728	30,171
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	159,728	159,728	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	1,554,061	515,843	1,038,217	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	6,405,729	416,890	-	2,348,631	779,584	1,022,044	304,623	219,390	388,338	161,496	184,765	44,474	272,690	91,199	164,902	6,704
	Expense Credits																
8	Sundry	(41,444)	(3,291)	(164)	(15,304)	(2,566)	(4,743)	(1,362)	(1,068)	(1,890)	(752)	(838)	(288)	(938)	(315)	(5,847)	(99)
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(249,068)	-	-	-	-	(144,048)	(49,229)	-	-	(25,497)	(30,295)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(7,848)	-	-	-	-	-	-	-	-	-	-	-	-	-	(7,848)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(298,359)	(3,291)	(164)	(15,304)	(2,566)	(148,790)	(50,591)	(1,068)	(1,890)	(26,248)	(31,132)	(288)	(938)	(315)	(13,695)	(99)
18	Subtotal Expenses	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776
21	Return on Debt	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921
22	Return on Equity	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057
23	Total Revenue Requirement	29,211,220	2,762,341	1,088,113	11,524,019	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	44,754

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	Revenue Related		20 Basis of Functional Classification
		18 Municipal Tax	19 PUB Assessment	
	Expenses			
1	Operating & Maintenance	571,245	34,268	Carryforward from Sch F 2.4 L.24
2	Fuels	-	-	
3	Fuels-Diesel	-	-	Production - Demand
4	Fuels-Gas Turbine	-	-	Production - Demand
5	Power Purchases -CF(L)Co	-	-	Carryforward from Sch F 4.4 L.17
6	Power Purchases-Other	-	-	Carryforward from Sch F 4.4 L.18
7	Depreciation	-	-	Carryforward from Sch F 2.5 L.24
	Expense Credits			
8	Sundry	(1,868)	(112)	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch F 2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch F 4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch F 4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	Total Expense Credits	(1,868)	(112)	
18	Subtotal Expenses	569,376	34,156	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch F 2.3 L.24
20	Subtotal Revenue Requirement Ex. Return	569,376	34,156	
21	Return on Debt	-	-	Prorated on Rate Base - Sch F 2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch F 2.6 L.11
23	Total Revenue Requirement	569,376	34,156	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Production																		
1	Gas Turbines	28,768,434	28,768,434	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Diesel	3,370,355	3,370,355	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Subtotal Production	32,138,789	32,138,789	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
4	Lines	4,560,341	-	-	4,560,341	-	-	-	-	-	-	-	-	-	-	-	-	
5	Terminal Stations	94,319,120	-	-	71,206,182	20,082,084	-	-	-	-	-	-	-	-	-	-	3,030,854	
6	Subtotal Transmission	98,879,461	-	-	75,766,523	20,082,084	-	-	-	-	-	-	-	-	-	-	3,030,854	
Distribution																		
7	Substations	12,569,787	-	-	-	12,569,787	-	-	-	-	-	-	-	-	-	-	-	
8	Land & Land Improvements	1,261,995	-	-	-	-	951,481	121,215	-	-	110,362	78,938	-	-	-	-	-	
9	Poles	43,568,475	-	-	-	-	25,197,741	8,611,396	-	-	4,460,018	5,299,321	-	-	-	-	-	
10	Primary Conductor & Eqpt	7,376,348	-	-	-	-	6,542,820	833,527	-	-	-	-	-	-	-	-	-	
11	Submarine Conductor	620,108	-	-	-	-	620,108	-	-	-	-	-	-	-	-	-	-	
12	Transformers	20,778,264	-	-	-	-	-	-	7,500,953	13,277,311	-	-	-	-	-	-	-	
13	Secondary Conductor&Eqpt	1,215,205	-	-	-	-	-	-	-	-	708,464	506,740	-	-	-	-	-	
14	Services	2,020,790	-	-	-	-	-	-	-	-	-	-	2,020,790	-	-	-	-	
15	Meters	4,544,442	-	-	-	-	-	-	-	-	-	-	-	4,544,442	-	-	-	
16	Street Lighting	2,215,553	-	-	-	-	-	-	-	-	-	-	-	-	2,215,553	-	-	
17	Subtotal Distribution	96,170,968	-	-	-	12,569,787	33,312,150	9,566,138	7,500,953	13,277,311	5,278,844	5,884,999	2,020,790	4,544,442	2,215,553	-	-	
18	Subttl Prod, Trans, & Dist	227,189,218	32,138,789	-	75,766,523	32,651,871	33,312,150	9,566,138	7,500,953	13,277,311	5,278,844	5,884,999	2,020,790	4,544,442	2,215,553	-	3,030,854	
19	General	25,144,749	1,664,749	-	10,311,823	1,291,113	2,838,804	815,210	639,218	1,131,470	449,854	501,509	172,208	606,044	188,806	4,424,635	109,306	
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Software - General	987,134	139,643	-	329,204	141,872	144,741	41,565	32,592	57,690	22,936	25,570	8,780	19,746	9,627	-	13,169	
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
24	Total Plant	253,321,102	33,943,181	-	86,407,551	34,084,855	36,295,695	10,422,913	8,172,763	14,466,470	5,751,634	6,412,079	2,201,779	5,170,232	2,413,985	4,424,635	3,153,329	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch F 4.1 L.9
2	Diesel	Production - Demand, Energy ratios Sch F 4.1 L.9
3	Subtotal Production	
	Transmission	
4	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
6	Subtotal Transmission	
	Distribution	
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.32
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.37
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.38
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.39
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch F 4.1 L.40
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.41
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	Subtotal Distribution	
18	Subttl Prod, Trans, & Dist	
19	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch F 2.4 L.11, 12
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
23	Software - Cust Acctng	
24	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Gas Turbines	10,673,663	10,673,663	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	384,172	384,172	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	11,057,835	11,057,835	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
4	Lines	3,536,019	-	-	3,536,019	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	86,402,412	-	-	73,946,857	12,394,404	-	-	-	-	-	-	-	-	-	-	61,151
6	Subtotal Transmission	89,938,431	-	-	77,482,876	12,394,404	-	-	-	-	-	-	-	-	-	-	61,151
Distribution																	
7	Substations	9,162,491	-	-	-	9,162,491	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	602,147	-	-	-	-	453,989	57,836	-	-	52,658	37,664	-	-	-	-	-
9	Poles	17,476,092	-	-	-	-	10,107,263	3,454,184	-	-	1,788,993	2,125,652	-	-	-	-	-
10	Primary Conductor & Eqpt	3,429,399	-	-	-	-	3,041,877	387,522	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	71,524	-	-	-	-	71,524	-	-	-	-	-	-	-	-	-	-
12	Transformers	9,301,909	-	-	-	-	-	-	3,357,989	5,943,920	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	322,268	-	-	-	-	-	-	-	-	187,882	134,386	-	-	-	-	-
14	Services	580,745	-	-	-	-	-	-	-	-	-	-	580,745	-	-	-	-
15	Meters	3,208,535	-	-	-	-	-	-	-	-	-	-	-	3,208,535	-	-	-
16	Street Lighting	1,011,870	-	-	-	-	-	-	-	-	-	-	-	-	1,011,870	-	-
17	Subtotal Distribution	45,166,980	-	-	-	9,162,491	13,674,652	3,899,543	3,357,989	5,943,920	2,029,533	2,297,702	580,745	3,208,535	1,011,870	-	-
18	Subttl Prod, Trans, & Dist	146,163,246	11,057,835	-	77,482,876	21,556,895	13,674,652	3,899,543	3,357,989	5,943,920	2,029,533	2,297,702	580,745	3,208,535	1,011,870	-	61,151
19	General	12,481,459	826,355	-	5,118,627	640,888	1,409,138	404,657	317,298	561,644	223,300	248,941	85,481	300,831	93,720	2,196,319	54,258
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	1,017,004	76,940	-	539,126	149,993	95,148	27,133	23,365	41,358	14,121	15,987	4,041	22,325	7,041	-	425
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Net Book Value	159,661,709	11,961,131	-	83,140,629	22,347,776	15,178,938	4,331,333	3,698,652	6,546,921	2,266,954	2,562,631	670,268	3,531,691	1,112,631	2,196,319	115,834

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Production																
1	Gas Turbine / Diesel	443,265	443,265	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	16,244	16,244	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	459,509	459,509	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	2,626,439	-	-	2,626,439	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	210,591	-	-	143,351	40,429	-	-	-	-	-	-	-	-	-	-	26,812
6	Other	100,147	-	-	76,509	20,279	-	-	-	-	-	-	-	-	-	-	3,359
7	Subtotal Transmission	2,937,178	-	-	2,846,299	60,708	-	-	-	-	-	-	-	-	-	-	30,171
	Distribution																
8	Other	2,155,257	-	-	-	295,669	783,575	225,017	176,439	312,311	124,170	138,428	47,533	-	52,115	-	-
9	Meters	167,282	-	-	-	-	-	-	-	-	-	-	-	167,282	-	-	-
10	Subtotal Distribution	2,322,539	-	-	-	295,669	783,575	225,017	176,439	312,311	124,170	138,428	47,533	167,282	52,115	-	-
11	Subttl Prod, Trans, & Dist	5,719,226	459,509	-	2,846,299	356,377	783,575	225,017	176,439	312,311	124,170	138,428	47,533	167,282	52,115	-	30,171
12	Customer Accounting	1,221,301	-	-	-	-	-	-	-	-	-	-	-	-	-	1,221,301	-
	Conservation and Demand Management	74,931	24,872	50,059													
	Administrative & General:																
	Plant-Related:																
13	Production	180,309	180,309	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	255,382	-	-	201,874	53,507	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	611,761	-	-	-	79,959	211,905	60,852	47,715	84,459	33,580	37,436	12,855	28,908	14,094	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn & General Plt	634,360	86,071	-	219,107	86,430	92,036	26,430	20,724	36,683	14,585	16,259	5,583	13,110	6,121	11,220	-
18	Property Insurance	214,760	45,082	-	108,716	45,268	3,786	1,087	852	1,509	600	669	230	808	252	5,901	-
	Revenue-Related:																
19	Municipal Tax	571,245	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	34,268	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	3,108,085	206,674	-	1,280,186	160,288	352,430	101,206	79,357	140,469	55,848	62,261	21,379	75,239	23,440	549,307	-
22	Prod, Trans & Distn Expense-Related	45,804	3,700	-	22,916	2,869	6,309	1,812	1,421	2,515	1,000	1,115	383	1,347	420	-	-
23	Subtotal Admin & General	5,655,974	521,835	-	1,832,800	428,322	666,466	191,387	150,069	265,635	105,612	117,739	40,429	119,412	44,326	566,428	-
24	Total Operating & Maintenance Expenses	12,671,431	1,006,216	50,059	4,679,099	784,698	1,450,041	416,403	326,508	577,947	229,782	256,167	87,963	286,694	96,441	1,787,728	30,171

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense (CONTD.)

Line No.	Description	1	18	19	20
			Revenue Related		
			Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production				
1	Gas Turbine / Diesel	-	-	-	Production - Demand, Energy ratios Sch F 4.1 L.9
2	Other	-	-	-	Production - Demand, Energy ratios Sch F 4.1 L.9
3	Subtotal Production	-	-	-	
	Transmission				
4	Transmission Lines	-	-	-	Prorated on Transmission Lines Plant in Service - Sch F 2.2 L.4
5	Terminal Stations	-	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch F 2.2 L.5
6	Other	-	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.6
7	Subtotal Transmission	-	-	-	
	Distribution				
8	Other	-	-	-	Prorated on Distribution Plant, excluding Meters - Sch F 2.2 L. 17, less L. 15
9	Meters	-	-	-	Meters - Customer
10	Subtotal Distribution	-	-	-	
11	Subttl Prod, Trans, & Dist	-	-	-	
12	Customer Accounting Conservation and Demand Management	-	-	-	Accounting - Customer
	Administrative & General:				
	Plant-Related:				
13	Production	-	-	-	Prorated on Production Plant in Service - Sch F 2.2 L.3
14	Transmission	-	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L. 6
15	Distribution	-	-	-	Prorated on Distribution Plant in Service - Sch F 2.2 L.17
16	Prod, Trans, Distn Plant	-	-	-	Prorated on Production, Transmission, Distribution Plant in Service - Sch F 2.2 L. 18
17	Prod, Trans, Distn & General Plt	-	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch F 2.2 L.24
18	Property Insurance	-	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch F 2.2 L.3, 5, 7, 19 - 20
	Revenue-Related:				
19	Municipal Tax	571,245	-	-	Revenue-related
20	PUB Assessment	-	34,268	-	Revenue-related
21	All Expense-Related	-	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 11, 12
22	Prod,Trans & Distn Expense-Related	-	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	571,245	34,268		
24	Total Operating & Maintenance Expenses	571,245	34,268		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected

Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Gas Turbines	323,490	323,490	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	17,541	17,541	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	341,031	341,031	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
4	Lines	86,938	-	-	86,938	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	2,242,671	-	-	1,800,904	439,240	-	-	-	-	-	-	-	-	-	-	2,528
6	Subtotal Transmission	2,329,609	-	-	1,887,841	439,240	-	-	-	-	-	-	-	-	-	-	2,528
Distribution																	
7	Substations	263,747	-	-	-	263,747	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	12,923	-	-	-	-	9,743	1,241	-	-	1,130	808	-	-	-	-	-
9	Poles	1,241,804	-	-	-	-	718,195	245,445	-	-	127,121	151,043	-	-	-	-	-
10	Primary Conductor & Equip	149,360	-	-	-	-	132,482	16,878	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	20,152	-	-	-	-	20,152	-	-	-	-	-	-	-	-	-	-
12	Transformers	520,645	-	-	-	-	-	-	187,953	332,692	-	-	-	-	-	-	-
13	Secondary Conductor & Equip	18,601	-	-	-	-	-	-	-	-	10,844	7,757	-	-	-	-	-
14	Services	36,575	-	-	-	-	-	-	-	-	-	-	36,575	-	-	-	-
15	Meters	240,366	-	-	-	-	-	-	-	-	-	-	-	240,366	-	-	-
16	Street Lighting	80,886	-	-	-	-	-	-	-	-	-	-	-	-	80,886	-	-
17	Subtotal Distribution	2,585,058	-	-	-	263,747	880,572	263,564	187,953	332,692	139,095	159,608	36,575	240,366	80,886	-	-
18	Subttl Prod, Trans, & Dist	5,255,698	341,031	-	1,887,841	702,988	880,572	263,564	187,953	332,692	139,095	159,608	36,575	240,366	80,886	-	2,528
19	General	937,122	62,044	-	384,312	48,119	105,800	30,382	23,823	42,169	16,766	18,691	6,418	22,587	7,037	164,902	4,074
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	GEC and AFUDC	29,095	1,888	-	10,451	3,892	4,875	1,459	1,040	1,842	770	884	202	1,331	448	-	14
22	Software - General	183,814	11,927	-	66,026	24,586	30,797	9,218	6,574	11,636	4,865	5,582	1,279	8,407	2,829	-	88
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Depreciation Expense	6,405,729	416,890	-	2,348,631	779,584	1,022,044	304,623	219,390	388,338	161,496	184,765	44,474	272,690	91,199	164,902	6,704

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
1	Average Net Book Value	159,661,709	11,961,131	-	83,140,629	22,347,776	15,178,938	4,331,333	3,698,652	6,546,921	2,266,954	2,562,631	670,268	3,531,691	1,112,631	2,196,319	115,834
2	Cash Working Capital	103,735	7,771	-	54,018	14,520	9,862	2,814	2,403	4,254	1,473	1,665	435	2,295	723	1,427	75
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	120,566	120,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	2,896,934	388,168	-	988,141	389,788	415,071	119,195	93,462	165,436	65,775	73,327	25,179	59,126	27,606	50,599	36,061
	Deferred Charges:																
	Foreign Exchange Loss and Regulatory																
7	Costs	7,674,183	574,915	-	3,996,177	1,074,152	729,580	208,187	177,777	314,680	108,962	123,174	32,217	169,752	53,479	105,567	5,568
8	Retire Asset Pool	8,203,333	614,556	-	4,271,721	1,148,217	779,886	222,542	190,035	336,377	116,475	131,667	34,438	181,456	57,166	112,846	5,951
9	Total Rate Base	178,660,460	13,667,107	-	92,450,686	24,974,453	17,113,337	4,884,070	4,162,329	7,367,668	2,559,639	2,892,463	762,537	3,944,320	1,251,605	2,466,758	163,489
10	Less: Rural Portion	-															
11	Rate Base Available for Equity Return	178,660,460	13,667,107	-	92,450,686	24,974,453	17,113,337	4,884,070	4,162,329	7,367,668	2,559,639	2,892,463	762,537	3,944,320	1,251,605	2,466,758	163,489
12	Return on Debt	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921
13	Return on Equity	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057
14	Return on Rate Base	8,718,630	666,955	-	4,511,593	1,218,753	835,131	238,343	203,122	359,542	124,910	141,152	37,212	192,483	61,078	120,378	7,978

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch F 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch F 2.2, L. 24
	Deferred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retire Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch F 1.1,p2,L.16
13	Return on Equity	L.11 x Sch F 1.1,p2,L.19
14	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Distribution										Accounting Customer	Specifically Assigned Customer
						Substations Demand	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Labrador Industrial Firm	-	317,009	2,026,309	298,387	-	-	-	-	-	-	-	-	-	-	-	-
3	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
4	1.1Domestic	-	741	2,552	698	673	673	316	636	316	636	316	316	316	-	316	-
5	1.1A Domestic All Electric	-	88,402	359,751	83,209	80,273	80,273	10,070	75,848	10,070	75,848	10,070	10,070	10,070	-	10,070	-
6	2.1GS 0-10 kW	-	914	4,960	861	830	830	429	785	429	785	429	804	804	-	429	-
7	2.2GS 10-100 kW	-	16,660	83,943	15,681	15,128	15,128	759	14,139	759	14,139	759	3,618	3,618	-	759	-
8	2.3GS 110-1,000 kVa	-	30,753	173,760	28,946	27,925	27,925	197	25,056	197	25,056	197	1,655	1,655	-	197	-
9	2.4GS Over 1,000 kVa	-	25,421	157,718	23,928	23,084	23,084	6	4,112	6	4,112	6	51	51	-	6	-
10	4.1Street and Area Lighting	-	268	1,085	252	243	243	398	230	398	230	398	-	-	1	398	-
11	Subtotal Rural	-	163,160	783,769	153,575	148,157	148,157	12,173	120,805	12,173	120,805	12,173	16,513	16,513	1	12,173	-
12	Total Labrador Interconnected	-	480,169	2,810,079	451,962	148,157	148,157	12,173	120,805	12,173	120,805	12,173	16,513	16,513	1	12,173	-
	Ratios																
13	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Labrador Industrial Firm	-	0.6602	0.7211	0.6602	-	-	-	-	-	-	-	-	-	-	-	-
15	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
16	1.1Domestic	-	0.0015	0.0009	0.0015	0.0045	0.0045	0.0259	0.0053	0.0259	0.0053	0.0259	0.0191	0.0191	-	0.0259	-
17	1.1A Domestic All Electric	-	0.1841	0.1280	0.1841	0.5418	0.5418	0.8272	0.6279	0.8272	0.6279	0.8272	0.6098	0.6098	-	0.8272	-
18	2.1GS 0-10 kW	-	0.0019	0.0018	0.0019	0.0056	0.0056	0.0352	0.0065	0.0352	0.0065	0.0352	0.0487	0.0487	-	0.0352	-
19	2.2GS 10-100 kW	-	0.0347	0.0299	0.0347	0.1021	0.1021	0.0623	0.1170	0.0623	0.1170	0.0623	0.2191	0.2191	-	0.0623	-
20	2.3GS 110-1,000 kVa	-	0.0640	0.0618	0.0640	0.1885	0.1885	0.0161	0.2074	0.0161	0.2074	0.0161	0.1002	0.1002	-	0.0161	-
21	2.4GS Over 1,000 kVa	-	0.0529	0.0561	0.0529	0.1558	0.1558	0.0005	0.0340	0.0005	0.0340	0.0005	0.0031	0.0031	-	0.0005	-
22	4.1Street and Area Lighting	-	0.0006	0.0004	0.0006	0.0016	0.0016	0.0327	0.0019	0.0327	0.0019	0.0327	-	-	1.0000	0.0327	-
23	Subtotal Rural	-	0.3398	0.2789	0.3398	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
24	Total Labrador Interconnected	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
	Ratios Excluding Labrador Industrial																
25	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
26	1.1Domestic	-	0.0045	0.0033	0.0045	0.0045	0.0045	0.0259	0.0053	0.0259	0.0053	0.0259	0.0191	0.0191	-	0.0259	-
27	1.1A Domestic All Electric	-	0.5418	0.4590	0.5418	0.5418	0.5418	0.8272	0.6279	0.8272	0.6279	0.8272	0.6098	0.6098	-	0.8272	-
28	2.1GS 0-10 kW	-	0.0056	0.0063	0.0056	0.0056	0.0056	0.0352	0.0065	0.0352	0.0065	0.0352	0.0487	0.0487	-	0.0352	-
29	2.2GS 10-100 kW	-	0.1021	0.1071	0.1021	0.1021	0.1021	0.0623	0.1170	0.0623	0.1170	0.0623	0.2191	0.2191	-	0.0623	-
30	2.3GS 110-1,000 kVa	-	0.1885	0.2217	0.1885	0.1885	0.1885	0.0161	0.2074	0.0161	0.2074	0.0161	0.1002	0.1002	-	0.0161	-
31	2.4GS Over 1,000 kVa	-	0.1558	0.2012	0.1558	0.1558	0.1558	0.0005	0.0340	0.0005	0.0340	0.0005	0.0031	0.0031	-	0.0005	-
32	4.1Street and Area Lighting	-	0.0016	0.0014	0.0016	0.0016	0.0016	0.0327	0.0019	0.0327	0.0019	0.0327	-	-	1.0000	0.0327	-
33	Subtotal Rural	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
34	Total Labrador Interconnected	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1	Revenue Related	
		18 Municipal Tax (Prior Year (Rural Revenues)	19 PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	CFB - Goose Bay Secondary	-	-
2	Labrador Industrial Firm	-	-
3	Labrador Industrial Non-Firm	-	-
	Rural		
4	1.1Domestic	94,365	94,365
5	1.1A Domestic All Electric	10,520,637	10,520,637
6	2.1GS 0-10 kW	345,486	345,486
7	2.2GS 10-100 kW	2,208,779	2,208,779
8	2.3GS 110-1,000 kVa	3,539,649	3,539,649
9	2.4GS Over 1,000 kVa	3,243,034	3,243,034
10	4.1Street and Area Lighting	361,265	361,265
11	Subtotal Rural	20,313,216	20,313,216
12	Total Labrador Interconnected	20,313,216	20,313,216
	Ratios		
13	CFB - Goose Bay Secondary	-	-
14	Labrador Industrial Firm	-	-
15	Labrador Industrial Non-Firm	-	-
	Rural		
16	1.1Domestic	0.0046	0.0046
17	1.1A Domestic All Electric	0.5179	0.5179
18	2.1GS 0-10 kW	0.0170	0.0170
19	2.2GS 10-100 kW	0.1087	0.1087
20	2.3GS 110-1,000 kVa	0.1743	0.1743
21	2.4GS Over 1,000 kVa	0.1597	0.1597
22	4.1Street and Area Lighting	0.0178	0.0178
23	Subtotal Rural	1.0000	1.0000
24	Total Labrador Interconnected	1.0000	1.0000
	Ratios Excluding Labrador Industrial		
25	CFB - Goose Bay Secondary	-	-
	Rural		
26	1.1Domestic	0.0046	0.0046
27	1.1A Domestic All Electric	0.5179	0.5179
28	2.1GS 0-10 kW	0.0170	0.0170
29	2.2GS 10-100 kW	0.1087	0.1087
30	2.3GS 110-1,000 kVa	0.1743	0.1743
31	2.4GS Over 1,000 kVa	0.1597	0.1597
32	4.1Street and Area Lighting	0.0178	0.0178
33	Subtotal Rural	1.0000	1.0000

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service																		
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)	
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)			
						Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)				
1	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
2	Labrador Industrial Firm	5,745,324	1,042,820	36,097	4,629,631	-	-	-	-	-	-	-	-	-	-	36,776		
3	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Rural:																		
4	1.1Domestic	160,727	4,783	3,425	10,828	7,097	10,558	17,376	2,869	24,995	1,922	10,621	2,525	10,670	-	50,253	-	
5	1.1A Domestic All Electric	9,049,493	570,294	482,877	1,291,031	846,159	1,258,792	554,611	342,074	797,785	229,186	339,002	80,587	340,549	-	1,603,964	-	
6	2.1GS 0-10 kW	237,724	5,899	6,657	13,353	8,752	13,020	23,600	3,538	33,947	2,370	14,425	6,438	27,207	-	68,252	-	
7	2.2GS 10-100 kW	1,431,773	107,473	112,673	243,298	159,461	237,222	41,775	63,768	60,091	42,724	25,535	28,955	122,359	-	120,815	-	
8	2.3GS 110-1,000 kVa	2,040,373	198,390	233,230	449,115	294,356	437,900	10,823	113,001	15,569	75,709	6,616	13,241	55,954	-	31,301	-	
9	2.4GS Over 1,000 kVa	1,483,657	163,997	211,697	371,255	243,326	361,985	330	18,543	475	12,424	202	404	1,708	-	956	-	
10	4.1Street and Area Lighting	343,518	1,729	1,457	3,915	2,566	3,817	21,920	1,037	31,531	695	13,399	-	-	187,324	63,394	-	
11	Subtotal Rural	14,747,265	1,052,566	1,052,016	2,382,795	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	-	
12	Total	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776	
Allocated Return on Debt																		
13	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Labrador Industrial Firm	2,113,708	271,595	-	1,837,193	-	-	-	-	-	-	-	-	-	-	-	4,921	
15	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
16	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Rural:																		
17	1.1Domestic	28,200	635	-	4,297	3,416	2,341	3,810	660	5,748	406	2,257	439	2,268	-	1,924	-	
18	1.1A Domestic All Electric	1,926,396	75,738	-	512,324	407,298	279,094	121,613	78,661	183,454	48,373	72,022	13,997	72,400	-	61,422	-	
19	2.1GS 0-10 kW	40,058	783	-	5,299	4,213	2,887	5,175	814	7,806	500	3,065	1,118	5,784	-	2,614	-	
20	2.2GS 10-100 kW	327,927	14,273	-	96,549	76,756	52,596	9,160	14,664	13,818	9,017	5,425	5,029	26,013	-	4,626	-	
21	2.3GS 110-1,000 kVa	508,066	26,347	-	178,224	141,688	97,089	2,373	25,985	3,580	15,980	1,406	2,300	11,896	-	1,199	-	
22	2.4GS Over 1,000 kVa	374,069	21,779	-	147,326	117,125	80,258	72	4,264	109	2,622	43	70	363	-	37	-	
23	4.1Street and Area Lighting	59,255	230	-	1,554	1,235	846	4,807	239	7,251	147	2,847	-	-	37,673	2,428	-	
24	Subtotal Rural	3,263,972	139,785	-	945,573	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	-	
25	Total	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921	
Allocated Return on Equity																		
26	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
27	Labrador Industrial Firm	1,313,168	168,732	-	1,141,379	-	-	-	-	-	-	-	-	-	-	-	3,057	
28	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Rural:																		
30	1.1Domestic	17,520	395	-	2,670	2,122	1,454	2,367	410	3,571	252	1,402	272	1,409	-	1,196	-	
31	1.1A Domestic All Electric	1,196,798	47,053	-	318,288	253,039	173,391	75,554	48,869	113,973	30,052	44,745	8,696	44,979	-	38,159	-	
32	2.1GS 0-10 kW	24,886	487	-	3,292	2,617	1,793	3,215	505	4,850	311	1,904	695	3,593	-	1,624	-	
33	2.2GS 10-100 kW	203,729	8,867	-	59,982	47,686	32,676	5,691	9,110	8,585	5,602	3,370	3,124	16,161	-	2,874	-	
34	2.3GS 110-1,000 kVa	315,642	16,368	-	110,724	88,025	60,318	1,474	16,144	2,224	9,928	873	1,429	7,390	-	745	-	
35	2.4GS Over 1,000 kVa	232,395	13,531	-	91,528	72,765	49,861	45	2,649	68	1,629	27	44	226	-	23	-	
36	4.1Street and Area Lighting	36,813	143	-	965	767	526	2,986	148	4,505	91	1,768	-	-	23,405	1,508	-	
37	Subtotal Rural	2,027,783	86,843	-	587,449	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	-	
38	Total	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	18	19	Basis of Proration
		Revenue Related		
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Rev Reqmt Excl Return			
1	CFB - Goose Bay Secondary	-	-	
2	Labrador Industrial Firm	-	-	
3	Labrador Industrial Non-Firm	-	-	
		-	-	
	Rural:			
4	1.1Domestic	2,645	159	
5	1.1A Domestic All Electric	294,892	17,690	
6	2.1GS 0-10 kW	9,684	581	
7	2.2GS 10-100 kW	61,912	3,714	
8	2.3GS 110-1,000 kVa	99,216	5,952	
9	2.4GS Over 1,000 kVa	90,902	5,453	
10	4.1Street and Area Lighting	10,126	607	
11	Subtotal Rural	569,376	34,156	
12	Total	569,376	34,156	
	Allocated Return on Debt			
13	CFB - Goose Bay Secondary	-	-	
14	Labrador Industrial Firm	-	-	
15	Labrador Industrial Non-Firm	-	-	
16	MFP Construction	-	-	
	Rural:			
17	1.1Domestic	-	-	
18	1.1A Domestic All Electric	-	-	
19	2.1GS 0-10 kW	-	-	
20	2.2GS 10-100 kW	-	-	
21	2.3GS 110-1,000 kVa	-	-	
22	2.4GS Over 1,000 kVa	-	-	
23	4.1Street and Area Lighting	-	-	
24	Subtotal Rural	-	-	
25	Total	-	-	
	Allocated Return on Equity			
26	CFB - Goose Bay Secondary	-	-	
27	Labrador Industrial Firm	-	-	
28	Labrador Industrial Non-Firm	-	-	
29	MFP Construction	-	-	
	Rural:			
30	1.1Domestic	-	-	
31	1.1A Domestic All Electric	-	-	
32	2.1GS 0-10 kW	-	-	
33	2.2GS 10-100 kW	-	-	
34	2.3GS 110-1,000 kVa	-	-	
35	2.4GS Over 1,000 kVa	-	-	
36	4.1Street and Area Lighting	-	-	
37	Subtotal Rural	-	-	
38	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO

2027 Test Year Cost of Service Study

Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
39	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Labrador Industrial Firm	9,172,200	1,483,146	36,097	7,608,202	-	-	-	-	-	-	-	-	-	-	-	44,754
41	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
43	1.1Domestic	206,448	5,813	3,425	17,795	12,636	14,353	23,554	3,939	34,314	2,580	14,280	3,236	14,347	-	53,373	-
44	1.1A Domestic All Electric	12,172,687	693,085	482,877	2,121,643	1,506,496	1,711,278	751,777	469,605	1,095,213	307,611	455,769	103,279	457,928	-	1,703,545	-
45	2.1GS 0-10 kW	302,668	7,169	6,657	21,944	15,582	17,700	31,990	4,857	46,604	3,182	19,394	8,251	36,584	-	72,489	-
46	2.2GS 10-100 kW	1,963,429	130,613	112,673	399,828	283,903	322,494	56,626	87,541	82,494	57,343	34,330	37,108	164,533	-	128,316	-
47	2.3GS 110-1,000 kVa	2,864,082	241,106	233,230	738,063	524,070	595,308	14,671	155,130	21,373	101,617	8,894	16,969	75,240	-	33,245	-
48	2.4GS Over 1,000 kVa	2,090,121	199,307	211,697	610,110	433,215	492,103	448	25,456	653	16,675	272	518	2,297	-	1,015	-
49	4.1Street and Area Lighting	439,585	2,102	1,457	6,434	4,568	5,189	29,713	1,424	43,286	933	18,014	-	-	248,403	67,330	-
50	Subtotal Rural	20,039,020	1,279,194	1,052,016	3,915,817	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	-
51	Total	29,211,220	2,762,341	1,088,113	11,524,019	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	44,754
Re-classification of Revenue-Related																	
52	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Labrador Industrial Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
56	1.1Domestic	-	80	47	245	174	198	324	54	472	36	197	45	198	-	735	-
57	1.1A Domestic All Electric	0	18,267	12,727	55,917	39,705	45,102	19,814	12,377	28,865	8,107	12,012	2,722	12,069	-	44,898	-
58	2.1GS 0-10 kW	-	252	234	770	547	621	1,123	171	1,636	112	681	290	1,284	-	2,545	-
59	2.2GS 10-100 kW	0	4,517	3,896	13,826	9,817	11,152	1,958	3,027	2,853	1,983	1,187	1,283	5,690	-	4,437	-
60	2.3GS 110-1,000 kVa	(0)	9,191	8,891	28,134	19,977	22,693	559	5,913	815	3,874	339	647	2,868	-	1,267	-
61	2.4GS Over 1,000 kVa	(0)	9,632	10,231	29,485	20,936	23,782	22	1,230	32	806	13	25	111	-	49	-
62	4.1Street and Area Lighting	0	53	36	161	114	130	744	36	1,083	23	451	-	-	6,217	1,685	-
63	Subtotal Rural	0	41,991	36,062	128,540	91,271	103,678	24,544	22,808	35,756	14,940	14,880	5,011	22,219	6,217	55,616	-
64	Total	0	41,991	36,062	128,540	91,271	103,678	24,544	22,808	35,756	14,940	14,880	5,011	22,219	6,217	55,616	-
Total Allocated Revenue Requirement																	
65	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Labrador Industrial Firm	9,172,200	1,483,146	36,097	7,608,202	-	-	-	-	-	-	-	-	-	-	-	44,754
67	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
69	1.1Domestic	206,448	5,893	3,472	18,040	12,809	14,551	23,878	3,993	34,786	2,616	14,476	3,280	14,545	-	54,108	-
70	1.1A Domestic All Electric	12,172,687	711,352	495,604	2,177,560	1,546,201	1,756,380	771,591	481,981	1,124,078	315,718	467,781	106,001	469,997	-	1,748,443	-
71	2.1GS 0-10 kW	302,668	7,420	6,891	22,715	16,129	18,321	33,113	5,028	48,240	3,293	20,075	8,541	37,868	-	75,034	-
72	2.2GS 10-100 kW	1,963,429	135,130	116,569	413,654	293,720	333,646	58,584	90,568	85,347	59,326	35,517	38,391	170,222	-	132,753	-
73	2.3GS 110-1,000 kVa	2,864,082	250,296	242,120	766,197	544,047	618,000	15,230	161,043	22,188	105,490	9,233	17,616	78,108	-	34,512	-
74	2.4GS Over 1,000 kVa	2,090,121	208,939	221,928	639,595	454,152	515,886	470	26,686	684	17,481	285	543	2,408	-	1,064	-
75	4.1Street and Area Lighting	439,585	2,154	1,493	6,595	4,683	5,319	30,456	1,460	44,370	956	18,464	-	-	254,620	69,015	-
76	Subtotal Rural	20,039,020	1,321,185	1,088,077	4,044,357	2,871,740	3,262,103	933,322	770,760	1,359,693	504,881	565,832	174,373	773,149	254,620	2,114,930	-
77	Total	29,211,220	2,804,331	1,124,174	11,652,559	2,871,740	3,262,103	933,322	770,760	1,359,693	504,881	565,832	174,373	773,149	254,620	2,114,930	44,754

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Interconnected

Line No.	Description	Allocation of Functionalized Amounts to Classes of Service (CONT'D.)		Basis of Proration
		18	19	
		Revenue Related		
		Municipal	PUB	
		Tax	Assessment	
		(\$)	(\$)	
	Total Revenue Requirement			
39	CFB - Goose Bay Secondary	-	-	
40	Labrador Industrial Firm	-	-	
41	Labrador Industrial Non-Firm	-	-	
42	MFP Construction	-	-	
	Rural:			
43	1.1Domestic	2,645	159	
44	1.1A Domestic All Electric	294,892	17,690	
45	2.1GS 0-10 kW	9,684	581	
46	2.2GS 10-100 kW	61,912	3,714	
47	2.3GS 110-1,000 kVa	99,216	5,952	
48	2.4GS Over 1,000 kVa	90,902	5,453	
49	4.1Street and Area Lighting	10,126	607	
50	Subtotal Rural	569,376	34,156	
51	Total	569,376	34,156	
	Re-classification of Revenue-Related			
52	CFB - Goose Bay Secondary	-	-	Re-classification to demand, energy and customer is based on rate class revenue
53	Labrador Industrial Firm	-	-	requirements excluding revenue-related items.
54	Labrador Industrial Non-Firm	-	-	
55	MFP Construction	-	-	
	Rural:			
56	1.1Domestic	(2,645)	(159)	
57	1.1A Domestic All Electric	(294,892)	(17,690)	
58	2.1GS 0-10 kW	(9,684)	(581)	
59	2.2GS 10-100 kW	(61,912)	(3,714)	
60	2.3GS 110-1,000 kVa	(99,216)	(5,952)	
61	2.4GS Over 1,000 kVa	(90,902)	(5,453)	
62	4.1Street and Area Lighting	(10,126)	(607)	
63	Subtotal Rural	(569,376)	(34,156)	
64	Total	(569,376)	(34,156)	
	Total Allocated Revenue Requirement			
65	CFB - Goose Bay Secondary	-	-	
66	Labrador Industrial Firm	-	-	
67	Labrador Industrial Non-Firm	-	-	
68	MFP Construction	-	-	
	Rural:			
69	1.1Domestic	-	-	
70	1.1A Domestic All Electric	-	-	
71	2.1GS 0-10 kW	-	-	
72	2.2GS 10-100 kW	-	-	
73	2.3GS 110-1,000 kVa	-	-	
74	2.4GS Over 1,000 kVa	-	-	
75	4.1Street and Area Lighting	-	-	
76	Subtotal Rural	-	-	
77	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmissior Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Expenses																
1	Operating & Maintenance	5,763,854	2,690,721	1,634,887	-	98,697	472,156	151,456	59,802	105,854	97,480	105,379	51,148	37,549	44,310	171,374	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	2,124,200	-	2,124,200	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	177,100	-	177,100	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,117,417	550,822	336,417	-	36,651	72,856	23,537	9,703	17,175	13,541	15,252	6,046	11,278	16,044	8,094	-
	Expense Credits																
8	Sundry	(18,852)	(8,800)	(5,347)	-	(323)	(1,544)	(495)	(196)	(346)	(319)	(345)	(167)	(123)	(145)	(561)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(20,860)	-	-	-	-	(12,065)	(4,123)	-	-	(2,135)	(2,537)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(216)	-	-	-	-	-	-	-	-	-	-	-	-	-	(216)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(39,928)	(8,800)	(5,347)	-	(323)	(13,609)	(4,618)	(196)	(346)	(2,454)	(2,882)	(167)	(123)	(145)	(777)	-
18	Subtotal Expenses	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-
21	Return on Debt	778,420	388,659	243,978	-	36,330	42,855	13,759	5,976	10,577	8,040	8,992	4,130	5,200	7,172	2,753	-
22	Return on Equity	483,603	241,459	151,574	-	22,570	26,624	8,548	3,712	6,571	4,995	5,586	2,566	3,230	4,456	1,711	-
23	Total Revenue Requirement	10,404,667	3,862,861	4,662,809	-	193,925	600,882	192,682	78,997	139,832	121,602	132,328	63,723	57,134	71,837	183,156	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Functional Classification	20
		Municipal Tax	PUB Assessment		
	Expenses				
1	Operating & Maintenance	40,605	2,436	Carryforward from Sch F 2.4 L.25	
2	Fuels	-	-	Production - Energy	
3	Fuels-Diesel	-	-	Production - Energy	
4	Fuels-Gas Turbine	-	-	Production - Energy	
5	Power Purchases -CF(L)Co	-	-		
6	Power Purchases-Other	-	-		
7	Depreciation	-	-	Carryforward from Sch F 2.5 L.23	
	Expense Credits				
8	Sundry	(133)	(8)	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.25	
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch F 2.2 L.17	
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.25	
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.25	
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch F 4.1 L.37	
13	Secondary Energy Revenues	-	-	Production - Energy	
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch F 4.1 L.16	
15	Application Fees	-	-	Accounting - Customer	
16	Meter Test Revenues	-	-	Meters - Customer	
17	Total Expense Credits	(133)	(8)		
18	Subtotal Expenses	40,472	2,428		
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch F 2.3 L.23	
20	Subtotal Revenue Requirement Ex. Return	40,472	2,428		
21	Return on Debt	-	-	Prorated on Rate Base - Sch F 2.6 L.9	
22	Return on Equity	-	-	Prorated on Rate Base - Sch F 2.6 L.11	
23	Total Revenue Requirement	40,472	2,428		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated

Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	8,490,207	5,264,340	3,225,867	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	8,490,207	5,264,340	3,225,867	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	651,069	121,854	-	-	529,215	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	32,475	-	-	-	-	24,484	3,119	-	-	2,840	2,031	-	-	-	-	-
8	Poles	3,975,794	-	-	-	-	2,299,392	785,824	-	-	406,994	483,584	-	-	-	-	-
9	Primary Conductor & Equipment	253,596	-	-	-	-	224,940	28,656	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	894,252	-	-	-	-	-	-	322,825	571,427	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	199,639	-	-	-	-	-	-	-	-	116,390	83,250	-	-	-	-	-
13	Services	276,111	-	-	-	-	-	-	-	-	-	-	276,111	-	-	-	-
14	Meters	196,359	-	-	-	-	-	-	-	-	-	-	-	196,359	-	-	-
15	Street Lighting	239,198	-	-	-	-	-	-	-	-	-	-	-	-	239,198	-	-
16	Subtotal Distribution	6,718,493	121,854	-	-	529,215	2,548,816	817,599	322,825	571,427	526,224	568,865	276,111	196,359	239,198	-	-
17	Subttl Prod, Trans, & Dist	15,208,700	5,386,194	3,225,867	-	529,215	2,548,816	817,599	322,825	571,427	526,224	568,865	276,111	196,359	239,198	-	-
18	General	3,753,373	2,029,573	1,240,180	-	24,777	119,332	38,279	15,114	26,753	24,637	26,633	12,927	10,376	11,199	173,592	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	66,082	23,403	14,016	-	2,299	11,075	3,552	1,403	2,483	2,286	2,472	1,200	853	1,039	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Plant	19,028,155	7,439,171	4,480,064	-	556,291	2,679,223	859,430	339,342	600,663	553,147	597,970	290,238	207,588	251,437	173,592	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONTD.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch F 4.1 L.6
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch F 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch F 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	15,938,486	9,882,633	6,055,853	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	15,938,486	9,882,633	6,055,853	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	1,012,596	14,673	-	-	997,923	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	7,638	-	-	-	-	5,759	734	-	-	668	478	-	-	-	-	-
8	Poles	1,747,765	-	-	-	-	1,010,817	345,449	-	-	178,915	212,584	-	-	-	-	-
9	Primary Conductor & Equipment	115,113	-	-	-	-	102,105	13,008	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	434,841	-	-	-	-	-	-	156,978	277,864	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	49,456	-	-	-	-	-	-	-	-	28,833	20,623	-	-	-	-	-
13	Services	106,892	-	-	-	-	-	-	-	-	-	-	106,892	-	-	-	-
14	Meters	138,636	-	-	-	-	-	-	-	-	-	-	-	138,636	-	-	-
15	Street Lighting	192,904	-	-	-	-	-	-	-	-	-	-	-	-	192,904	-	-
16	Subtotal Distribution	3,805,842	14,673	-	-	997,923	1,118,681	359,191	156,978	277,864	208,416	233,685	106,892	138,636	192,904	-	-
17	Subttl Prod, Trans, & Dist	19,744,328	9,897,307	6,055,853	-	997,923	1,118,681	359,191	156,978	277,864	208,416	233,685	106,892	138,636	192,904	-	-
18	General	1,636,872	885,111	540,851	-	10,805	52,041	16,694	6,591	11,667	10,744	11,615	5,638	4,525	4,884	75,705	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	137,381	68,865	42,137	-	6,944	7,784	2,499	1,092	1,933	1,450	1,626	744	965	1,342	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Net Book Value	21,518,581	10,851,283	6,638,840	-	1,015,672	1,178,506	378,384	164,661	291,464	220,610	246,926	113,273	144,126	199,131	75,705	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)			
	Production																	
1	Diesel	2,065,682	1,280,823	784,859	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Other	208,062	129,008	79,053	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Subtotal Production	2,273,744	1,409,831	863,912	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Transmission																	
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Distribution																	
8	Other	212,712	3,974	-	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	-	7,801	-	-	
9	Meters	7,228	-	-	-	-	-	-	-	-	-	-	-	7,228	-	-	-	
10	Subtotal Distribution	219,940	3,974	-	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	7,228	7,801	-	-	
11	Subttl Prod, Trans, & Dist	2,493,683	1,413,805	863,912	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	7,228	7,801	-	-	
12	Customer Accounting	120,925	-	-	-	-	-	-	-	-	-	-	-	-	-	120,925	-	
	Administrative & General:																	
	Plant-Related:																	
13	Production	962,970	597,088	365,882	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Distribution	862,064	15,635	-	-	67,905	327,044	104,908	41,422	73,321	67,521	72,992	35,428	25,195	30,692	-	-	
16	Prod, Trans, Distn Plant	157,713	55,855	33,452	-	5,488	26,431	8,478	3,348	5,926	5,457	5,899	2,863	2,036	2,480	-	-	
17	Prod, Trans, Distn and Gen Plt	1,547	605	364	-	45	218	70	28	49	45	49	24	17	20	14	-	
18	Property Insurance	16,132	9,277	5,587	-	693	149	48	19	33	31	33	16	13	14	217	-	
	Revenue Related:																	
20	Municipal Tax	40,605	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	PUB Assessment	2,436	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	All Expense-Related	1,085,807	587,132	358,770	-	7,168	34,521	11,074	4,372	7,739	7,127	7,705	3,740	3,002	3,240	50,218	-	
23	Prod, Trans, and Distn Expense-Related	19,971	11,323	6,919	-	138	666	214	84	149	137	149	72	58	62	-	-	
24	Subtotal Admin & General	3,149,246	1,276,915	770,974	-	81,437	389,029	124,791	49,273	87,218	80,318	86,827	42,143	30,321	36,509	50,450	-	
25	Total Operating & Maintenance Expenses	5,763,854	2,690,721	1,634,887	-	98,697	472,156	151,456	59,802	105,854	97,480	105,379	51,148	37,549	44,310	171,374	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

		18	19	20
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch F 4.1 L6
2	Other	-	-	Production - Demand, Energy ratios Sch F 4.1 L6
3	Subtotal Production	<u>-</u>	<u>-</u>	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch F 2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch F 2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.5
7	Subtotal Transmission	<u>-</u>	<u>-</u>	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch F 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	Subtotal Distribution	<u>-</u>	<u>-</u>	
11	Subttl Prod, Trans, & Dist	<u>-</u>	<u>-</u>	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch F 2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch F 2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch F 2.2 L.17
17	Prod, Trans, Distn and Gen Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch F 2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch F 2.2 L.2, 4, 6, 18 - 19
19	Revenue Related:			
20	Municipal Tax	40,605	-	Revenue-related
21	PUB Assessment	-	2,436	Revenue-related
22	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
23	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
24	Subtotal Admin & General	<u>40,605</u>	<u>2,436</u>	
25	Total Operating & Maintenance Expenses	<u>40,605</u>	<u>2,436</u>	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Depreciation Expense

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
		Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Production																		
1	Diesel	705,506	437,448	268,058	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	705,506	437,448	268,058	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																		
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																		
6	Substn Struct & Eqpt	35,648	1,494	-	-	34,153	-	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	213	-	-	-	-	160	20	-	-	19	13	-	-	-	-	-	-
8	Poles	102,292	-	-	-	-	59,161	20,218	-	-	10,471	12,442	-	-	-	-	-	-
9	Primary Conductor & Equipment	6,118	-	-	-	-	5,427	691	-	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	23,984	-	-	-	-	-	-	8,658	15,326	-	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	2,459	-	-	-	-	-	-	-	-	1,434	1,025	-	-	-	-	-	-
13	Services	5,237	-	-	-	-	-	-	-	-	-	-	5,237	-	-	-	-	-
14	Meters	10,386	-	-	-	-	-	-	-	-	-	-	-	10,386	-	-	-	-
15	Street Lighting	14,935	-	-	-	-	-	-	-	-	-	-	-	-	14,935	-	-	-
16	Subtotal Distribution	201,272	1,494	-	-	34,153	64,748	20,930	8,658	15,326	11,924	13,481	5,237	10,386	14,935	-	-	-
17	Subtotal Prod Tran & Dist	906,778	438,942	268,058	-	34,153	64,748	20,930	8,658	15,326	11,924	13,481	5,237	10,386	14,935	-	-	-
18	General	175,004	94,630	57,824	-	1,155	5,564	1,785	705	1,247	1,149	1,242	603	484	522	8,094	-	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	3,921	1,898	1,159	-	148	280	91	37	66	52	58	23	45	65	-	-	-
21	Software - General	31,714	15,352	9,375	-	1,194	2,265	732	303	536	417	471	183	363	522	-	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	1,117,417	550,822	336,417	-	36,651	72,856	23,537	9,703	17,175	13,541	15,252	6,046	11,278	16,044	8,094	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Rate Base

Line No.	Description	2 Total Amount (\$)	3 Production Demand (\$)	4 Production Energy (\$)	5 Transmission Demand (\$)	6 Substations Demand (\$)	7 Primary Lines Demand (\$)	8 Customer (\$)	9 Line Transformers Demand (\$)	10 Customer (\$)	11 Distribution Secondary Lines Demand (\$)	12 Customer (\$)	13 Services Customer (\$)	14 Meters Customer (\$)	15 Street Lighting Customer (\$)	16 Accounting Customer (\$)	17 Specifically Assigned Customer (\$)
1	Average Net Book Value	21,518,581	10,851,283	6,638,840	-	1,015,672	1,178,506	378,384	164,661	291,464	220,610	246,926	113,273	144,126	199,131	75,705	-
2	Cash Working Capital	13,981	7,050	4,313	-	660	766	246	107	189	143	160	74	94	129	49	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	206,653	-	206,653	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	217,603	85,073	51,233	-	6,362	30,639	9,828	3,881	6,869	6,326	6,838	3,319	2,374	2,875	1,985	-
	Ueterrred Charges: Foreign Exchange Loss and Regulatory																
7	Costs	1,034,296	521,570	319,098	-	48,819	56,645	18,187	7,914	14,009	10,604	11,869	5,445	6,927	9,571	3,639	-
8	Retired Asset Pool	2,870,021	1,447,280	885,449	-	135,464	157,182	50,467	21,962	38,874	29,424	32,934	15,108	19,223	26,559	10,097	-
9	Total Rate Base	25,861,135	12,912,256	8,105,587	-	1,206,976	1,423,738	457,111	198,525	351,406	267,107	298,727	137,218	172,743	238,266	91,475	-
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rate Base Available for Equity Return	25,861,135	12,912,256	8,105,587	-	1,206,976	1,423,738	457,111	198,525	351,406	267,107	298,727	137,218	172,743	238,266	91,475	-
12	Return on Debt	778,420	388,659	243,978	-	36,330	42,855	13,759	5,976	10,577	8,040	8,992	4,130	5,200	7,172	2,753	-
13	Return on Equity	483,603	241,459	151,574	-	22,570	26,624	8,548	3,712	6,571	4,995	5,586	2,566	3,230	4,456	1,711	-
14	Return on Rate Base	1,262,023	630,118	395,553	-	58,900	69,478	22,307	9,688	17,149	13,035	14,578	6,696	8,430	11,627	4,464	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch F 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch F 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch F 1.1,p2,L.16
13	Return on Equity	L.11 x Sch F 1.1,p2,L.19
14	Return on Rate Base	

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NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	658,743	658,743
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	43,910	43,910
4	2.1 GS 0-10 kW	205,170	205,170
5	2.2 GS 10-100 kW	491,702	491,702
6	2.3 GS 110-1,000 kVa	-	-
7	2.4 GS Over 1,000 kVa	-	-
8	4.1 Street and Area Lighting	38,040	38,040
9	4.1G Gov't Street and Area Lighting	6,323	6,323
10	Total	1,443,889	1,443,889
	Ratios		
11	1.2 Domestic Diesel	0.4562	0.4562
12	1.2G Government Domestic Diesel	-	-
13	1.23 Churches, Schools & Com Halls	0.0304	0.0304
14	2.1 GS 0-10 kW	0.1421	0.1421
15	2.2 GS 10-100 kW	0.3405	0.3405
16	2.3 GS 110-1,000 kVa	-	-
17	2.4 GS Over 1,000 kVa	-	-
18	4.1 Street and Area Lighting	0.0263	0.0263
19	4.1G Gov't Street and Area Lighting	0.0044	0.0044

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated

Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Allocated Revenue Requirement Excluding Return																	
1	1.2 Domestic Diesel	6,757,294	2,531,252	2,982,840	-	105,725	416,091	139,262	54,270	100,280	85,008	96,247	43,519	37,167	-	146,060	-
2	1.2G Government Domestic Diesel	48,553	19,622	20,707	-	820	3,226	767	421	553	659	530	240	205	-	805	-
3	1.23 Churches, Schools & Com Halls	325,166	95,658	187,724	-	3,995	15,724	3,836	2,051	2,763	3,213	2,651	1,199	1,024	-	4,024	-
4	2.1 GS 0-10 kW	731,952	183,957	420,985	-	7,683	30,239	16,023	3,944	11,538	6,178	11,074	9,401	8,029	-	16,805	-
5	2.2 GS 10-100 kW	1,138,127	382,631	629,811	-	15,982	62,898	1,790	8,204	1,289	12,850	1,237	2,669	2,279	-	1,878	-
6	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	4.1 Street and Area Lighting	141,363	19,622	25,189	-	820	3,226	8,696	421	6,262	659	6,010	-	-	60,209	9,120	-
9	4.1G Gov't Street and Area Lighting	188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-
Allocated Return on Debt and Equity																	
11	1.2 Domestic Diesel	947,551	493,385	276,494	-	46,119	54,402	18,233	7,586	14,017	10,206	11,916	5,110	6,433	-	3,649	-
12	1.2G Government Domestic Diesel	6,911	3,825	1,919	-	358	422	100	59	-	79	66	28	35	-	20	-
13	1.23 Churches, Schools & Com Halls	42,153	18,645	17,401	-	1,743	2,056	502	287	386	386	328	141	177	-	101	-
14	2.1 GS 0-10 kW	91,473	35,856	39,023	-	3,352	3,954	2,098	551	1,613	742	1,371	1,104	1,390	-	420	-
15	2.2 GS 10-100 kW	152,169	74,582	58,380	-	6,972	8,224	234	1,147	180	1,543	153	313	395	-	47	-
16	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	4.1 Street and Area Lighting	21,690	3,825	2,335	-	358	422	1,139	59	875	79	744	-	-	11,627	228	-
19	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total	1,261,946	630,118	395,553	-	58,900	69,478	22,307	9,688	17,071	13,035	14,578	6,696	8,430	11,627	4,464	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1	18 Revenue Related		19	Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)		
	Allocated Revenue Requirement Excluding Return				
1	1.2 Domestic Diesel	18,464	1,108		
2	1.2G Government Domestic Diesel	-	-		
3	1.23 Churches, Schools & Com Halls	1,231	74		
4	2.1 GS 0-10 kW	5,751	345		
5	2.2 GS 10-100 kW	13,782	827		
6	2.3 GS 110-1,000 kVa	-	-		
7	2.4 GS Over 1,000 kVa	-	-		
8	4.1 Street and Area Lighting	1,066	64		
9	4.1G Gov't Street and Area Lighting	177	11		
10	Total	40,472	2,428		
	Allocated Return on Debt and Equity				
11	1.2 Domestic Diesel	-	-		
12	1.2G Government Domestic Diesel	-	-		
13	1.23 Churches, Schools & Com Halls	-	-		
14	2.1 GS 0-10 kW	-	-		
15	2.2 GS 10-100 kW	-	-		
16	2.3 GS 110-1,000 kVa	-	-		
17	2.4 GS Over 1,000 kVa	-	-		
18	4.1 Street and Area Lighting	-	-		
19	4.1G Gov't Street and Area Lighting	-	-		
20	Total	-	-		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmissior Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Total Revenue Requirement																
21	1.2 Domestic Diesel	7,704,844	3,024,638	3,259,334	-	151,844	470,493	157,496	61,855	114,297	95,215	108,163	48,629	43,600	-	149,709	-
22	1.2G Government Domestic Diesel	55,464	23,447	22,627	-	1,177	3,647	868	479	553	738	596	268	240	-	825	-
23	1.23 Churches, Schools & Com Halls	367,319	114,303	205,125	-	5,738	17,780	4,339	2,338	3,149	3,598	2,980	1,340	1,201	-	4,124	-
24	2.1 GS 0-10 kW	823,425	219,814	460,008	-	11,035	34,193	18,121	4,495	13,151	6,920	12,445	10,505	9,418	-	17,225	-
25	2.2 GS 10-100 kW	1,290,296	457,213	688,192	-	22,953	71,121	2,025	9,350	1,469	14,393	1,391	2,982	2,674	-	1,925	-
26	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	4.1 Street and Area Lighting	163,053	23,447	27,524	-	1,177	3,647	9,834	479	7,137	738	6,754	-	-	71,837	9,348	-
29	4.1G Gov't Street and Area Lighting	188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total	10,404,589	3,862,861	4,662,809	-	193,925	600,882	192,682	78,997	139,755	121,602	132,328	63,723	57,134	71,837	183,156	-
	Re-classification of Revenue-Related																
31	1.2 Domestic Diesel	(0)	7,703	8,301	-	387	1,198	401	158	291	242	275	124	111	-	381	-
32	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	1.23 Churches, Schools & Com Halls	-	407	731	-	20	63	15	8	11	13	11	5	4	-	15	-
34	2.1 GS 0-10 kW	-	1,639	3,431	-	82	255	135	34	98	52	93	78	70	-	128	-
35	2.2 GS 10-100 kW	-	5,236	7,881	-	263	814	23	107	17	165	16	34	31	-	22	-
36	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	4.1 Street and Area Lighting	0	164	192	-	8	25	69	3	50	5	47	-	-	501	65	-
39	4.1G Gov't Street and Area Lighting	(188)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Total	(188)	15,149	20,536	-	761	2,357	644	310	467	477	442	241	216	501	612	-
	Total Allocated Revenue Requirement																
41	1.2 Domestic Diesel	7,704,844	3,032,340	3,267,635	-	152,231	471,692	157,897	62,013	114,588	95,457	108,438	48,753	43,711	-	150,090	-
42	1.2G Government Domestic Diesel	55,464	23,447	22,627	-	1,177	3,647	868	479	553	738	596	268	240	-	825	-
43	1.23 Churches, Schools & Com Halls	367,319	114,711	205,856	-	5,759	17,844	4,354	2,346	3,160	3,611	2,990	1,344	1,205	-	4,139	-
44	2.1 GS 0-10 kW	823,425	221,453	463,439	-	11,117	34,448	18,256	4,529	13,249	6,971	12,538	10,583	9,489	-	17,353	-
45	2.2 GS 10-100 kW	1,290,296	462,449	696,073	-	23,216	71,936	2,048	9,457	1,486	14,558	1,406	3,016	2,704	-	1,947	-
46	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	4.1 Street and Area Lighting	163,053	23,610	27,716	-	1,185	3,673	9,903	483	7,187	743	6,801	-	-	72,338	9,413	-
49	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total	10,404,402	3,878,010	4,683,345	-	194,685	603,239	193,326	79,307	140,222	122,079	132,770	63,964	57,350	72,338	183,767	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Island Isolated

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

		18	19	
		Revenue Related		
Line No.	Description	Municipal	PUB	Basis of Proration
		Tax (\$)	Assessment (\$)	
	Total Revenue Requirement			
21	1.2 Domestic Diesel	18,464	1,108	
22	1.2G Government Domestic Diesel	-	-	
23	1.23 Churches, Schools & Com Halls	1,231	74	
24	2.1 GS 0-10 kW	5,751	345	
25	2.2 GS 10-100 kW	13,782	827	
26	2.3 GS 110-1,000 kVa	-	-	
27	2.4 GS Over 1,000 kVa	-	-	
28	4.1 Street and Area Lighting	1,066	64	
29	4.1G Gov't Street and Area Lighting	177	11	
30	Total	40,472	2,428	
	Re-classification of Revenue-Related			
31	1.2 Domestic Diesel	(18,464)	(1,108)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
32	1.2G Government Domestic Diesel	-	-	
33	1.23 Churches, Schools & Com Halls	(1,231)	(74)	
34	2.1 GS 0-10 kW	(5,751)	(345)	
35	2.2 GS 10-100 kW	(13,782)	(827)	
36	2.3 GS 110-1,000 kVa	-	-	
37	2.4 GS Over 1,000 kVa	-	-	
38	4.1 Street and Area Lighting	(1,066)	(64)	
39	4.1G Gov't Street and Area Lighting	(177)	(11)	
40	Total	(40,472)	(2,428)	
	Total Allocated Revenue Requirement			
41	1.2 Domestic Diesel	-	-	
42	1.2G Government Domestic Diesel	-	-	
43	1.23 Churches, Schools & Com Halls	-	-	
44	2.1 GS 0-10 kW	-	-	
45	2.2 GS 10-100 kW	-	-	
46	2.3 GS 110-1,000 kVa	-	-	
47	2.4 GS Over 1,000 kVa	-	-	
48	4.1 Street and Area Lighting	-	-	
49	4.1G Gov't Street and Area Lighting	-	-	
50	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
	Expenses																	
1	Operating & Maintenance	15,269,542	5,991,478	6,961,699	-	83,194	565,904	166,641	72,366	128,094	90,533	101,676	47,574	70,738	22,397	687,523	-	
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Fuels-Diesel	17,415,200	-	17,415,200	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Power Purchases-Other	309,793	-	309,793	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Depreciation	5,466,481	2,204,841	2,565,232	-	37,836	246,484	74,299	39,408	69,755	39,341	44,891	19,722	58,914	28,853	36,904	-	
	Expense Credits																	
8	Sundry	(49,941)	(19,596)	(22,769)	-	(272)	(1,851)	(545)	(237)	(419)	(296)	(333)	(156)	(231)	(73)	(2,249)	-	
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Pole Attachments	(107,593)	-	-	-	-	(62,226)	(21,266)	-	-	(11,014)	(13,087)	-	-	-	-	-	
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Application Fees	(1,176)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,176)	-	
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	Total Expense Credits	(158,711)	(19,596)	(22,769)	-	(272)	(64,077)	(21,811)	(237)	(419)	(11,310)	(13,419)	(156)	(231)	(73)	(3,425)	-	
18	Subtotal Expenses	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-	
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Subtotal Revenue Requirement Ex. Return	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-	
21	Return on Debt	3,616,593	1,400,804	1,802,059	-	37,339	142,825	42,315	27,122	48,008	22,662	25,628	15,165	27,260	10,894	14,514	-	
22	Return on Equity	2,246,853	870,267	1,119,551	-	23,197	88,732	26,289	16,850	29,825	14,079	15,922	9,421	16,935	6,768	9,017	-	
23	Total Revenue Requirement	44,165,752	10,447,794	30,150,766	-	181,293	979,867	287,733	155,509	275,264	155,305	174,698	91,727	173,615	68,839	744,534	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 20 Basis of Functional Classification
		Municipal Tax	PUB Assessment	
	Expenses			
1	Operating & Maintenance	263,893	15,830	Carryforward from Sch F 2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch F 4.4 L.20
7	Depreciation	-	-	Carryforward from Sch F 2.5 L.23
	Expense Credits			
8	Sundry	(863)	(52)	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch F 2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch F 4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch F 4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	Total Expense Credits	(863)	(52)	
18	Subtotal Expenses	263,030	15,779	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch F 2.3 L.23
20	Subtotal Revenue Requirement Ex. Return	263,030	15,779	
21	Return on Debt	-	-	Prorated on Rate Base - Sch F 2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch F 2.6 L.11
23	Total Revenue Requirement	263,030	15,779	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated

Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution												Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)		
Production																		
1	Diesel	101,424,536	46,346,579	55,077,957	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Subtotal Production	101,424,536	46,346,579	55,077,957	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution																		
6	Substation Structures & Equipment	3,834,105	2,361,427	-	-	1,472,678	-	-	-	-	-	-	-	-	-	-	-	
7	Land & Land Improvements	102,348	-	-	-	-	77,165	9,831	-	-	8,950	6,402	-	-	-	-	-	
8	Poles	13,745,724	-	-	-	-	7,949,812	2,716,870	-	-	1,407,122	1,671,920	-	-	-	-	-	
9	Primary Conductor & Equipment	2,449,563	-	-	-	-	2,172,763	276,801	-	-	-	-	-	-	-	-	-	
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Transformers	3,613,059	-	-	-	-	-	-	1,304,314	2,308,744	-	-	-	-	-	-	-	
12	Secondary Conductors & Equipment	369,948	-	-	-	-	-	-	-	-	215,680	154,268	-	-	-	-	-	
13	Services	857,470	-	-	-	-	-	-	-	-	-	-	857,470	-	-	-	-	
14	Meters	1,020,023	-	-	-	-	-	-	-	-	-	-	-	1,020,023	-	-	-	
15	Street Lighting	403,680	-	-	-	-	-	-	-	-	-	-	-	-	403,680	-	-	
16	Subtotal Distribution	26,395,920	2,361,427	-	-	1,472,678	10,199,740	3,003,501	1,304,314	2,308,744	1,631,753	1,832,590	857,470	1,020,023	403,680	-	-	
17	Subttl Prod, Trans, & Dist	127,820,456	48,708,006	55,077,957	-	1,472,678	10,199,740	3,003,501	1,304,314	2,308,744	1,631,753	1,832,590	857,470	1,020,023	403,680	-	-	
18	General	16,188,197	6,554,928	7,658,499	-	68,920	477,339	140,561	61,041	108,047	76,365	85,764	40,129	64,777	18,892	832,935	-	
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Software - General	555,378	211,636	239,313	-	6,399	44,318	13,050	5,667	10,031	7,090	7,963	3,726	4,432	1,754	-	-	
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
23	Total Plant	144,564,032	55,474,569	62,975,769	-	1,547,997	10,721,397	3,157,113	1,371,022	2,426,823	1,715,207	1,926,317	901,324	1,089,232	424,326	832,935	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch F 4.1 L.7
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch F 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch F 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Net Book Value

1		2	3	4	5	Distribution										16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)					
Production																	
1	Diesel	76,035,619	34,744,954	41,290,665	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	76,035,619	34,744,954	41,290,665	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	1,723,562	728,201	-	-	995,362	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	24,670	-	-	-	-	18,600	2,370	-	-	2,157	1,543	-	-	-	-	-
8	Poles	4,989,483	-	-	-	-	2,885,658	986,181	-	-	510,763	606,881	-	-	-	-	-
9	Primary Conductor & Equipment	851,171	-	-	-	-	754,989	96,182	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,981,705	-	-	-	-	-	-	715,396	1,266,310	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	115,342	-	-	-	-	-	-	-	-	67,244	48,098	-	-	-	-	-
13	Services	395,847	-	-	-	-	-	-	-	-	-	-	395,847	-	-	-	-
14	Meters	720,172	-	-	-	-	-	-	-	-	-	-	-	720,172	-	-	-
15	Street Lighting	291,251	-	-	-	-	-	-	-	-	-	-	-	-	291,251	-	-
16	Subtotal Distribution	11,093,204	728,201	-	-	995,362	3,659,247	1,084,733	715,396	1,266,310	580,165	656,521	395,847	720,172	291,251	-	-
17	Subttl Prod, Trans, & Dist	87,128,823	35,473,155	41,290,665	-	995,362	3,659,247	1,084,733	715,396	1,266,310	580,165	656,521	395,847	720,172	291,251	-	-
18	General	7,778,683	3,149,746	3,680,029	-	33,117	229,369	67,542	29,331	51,918	36,694	41,211	19,283	31,126	9,078	400,239	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	606,243	246,822	287,301	-	6,926	25,461	7,548	4,978	8,811	4,037	4,568	2,754	5,011	2,027	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Net Book Value	95,513,749	38,869,723	45,257,995	-	1,035,405	3,914,077	1,159,823	749,704	1,327,039	620,896	702,300	417,884	756,310	302,355	400,239	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
	Production																	
1	Diesel	7,944,573	3,630,322	4,314,250	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Other	230,067	105,131	124,937	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Subtotal Production	8,174,640	3,735,453	4,439,187	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Transmission																	
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Distribution																	
8	Other	688,366	64,058	-	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	-	10,951	-	-	
9	Meters	37,547	-	-	-	-	-	-	-	-	-	-	-	37,547	-	-	-	
10	Subtotal Distribution	725,913	64,058	-	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	37,547	10,951	-	-	
11	Subttl Prod, Trans, & Dist	8,900,553	3,799,511	4,439,187	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	37,547	10,951	-	-	
12	Customer Accounting	482,804	-	-	-	-	-	-	-	-	-	-	-	-	-	482,804	-	
	Administrative & General:																	
	Plant-Related:																	
13	Production	678,462	310,027	368,434	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Distribution	352,550	31,540	-	-	19,669	136,230	40,115	17,421	30,836	21,794	24,476	11,453	13,624	5,392	-	-	
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	Prod, Trans, Distn and General Plt	472,077	181,153	205,649	-	5,055	35,011	10,310	4,477	7,925	5,601	6,290	2,943	3,557	1,386	2,720	-	
18	Property Insurance	122,558	55,769	63,310	-	1,556	482	142	62	109	77	87	40	65	19	841	-	
	Revenue Related:																	
19	Municipal Tax	263,893	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	PUB Assessment	15,830	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	All Expense-Related	3,909,532	1,583,048	1,849,566	-	16,645	115,280	33,946	14,742	26,094	18,442	20,712	9,691	15,644	4,562	201,158	-	
22	Prod, Trans, and Distn Expense-Related	71,283	30,430	35,553	-	320	2,216	653	283	502	355	398	186	301	88	-	-	
23	Subtotal Admin & General	5,886,184	2,191,967	2,522,513	-	43,245	289,218	85,166	36,984	65,466	46,269	51,964	24,314	33,191	11,447	204,719	-	
	Total Operating & Maintenance Expenses	15,269,542	5,991,478	6,961,699	-	83,194	565,904	166,641	72,366	128,094	90,533	101,676	47,574	70,738	22,397	687,523	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 PUB Assessment	20 Basis of Functional Classification
		Municipal Tax			
	Production				
1	Diesel	-	-		Production - Demand, Energy ratios Sch F 4.1 L7
2	Other	-	-		Production - Demand, Energy ratios Sch F 4.1 L7
3	Subtotal Production	-	-		
	Transmission				
4	Transmission Lines	-	-		Prorated on Transmission Lines Plant in Service - Sch F 2.2 L.3
5	Terminal Stations	-	-		Prorated on Transmission Terminal Stations Plant in Service - Sch F 2.2 L.4
6	Other	-	-		Prorated on Transmission Plant in Service - Sch F 2.2 L.5
7	Subtotal Transmission	-	-		
	Distribution				
8	Other	-	-		Prorated on Distribution Plant, excluding Meters - Sch F 2.2 L. 16, less L. 14
9	Meters	-	-		Meters - Customer
10	Subtotal Distribution	-	-		
11	Subttl Prod, Trans, & Dist	-	-		
12	Customer Accounting	-	-		Accounting - Customer
	Administrative & General:				
	Plant-Related:				
13	Production	-	-		Prorated on Production Plant in Service - Sch F 2.2 L.2
14	Transmission	-	-		Prorated on Transmission Plant in Service - Sch F 2.2 L.5
15	Distribution	-	-		Prorated on Distribution Plant in Service - Sch F 2.2 L.16
16	Prod, Trans, Distn Plant	-	-		Prorated on Production, Transmission & Distribution Plant in Service - Sch F 2.2 L.17
17	Prod, Trans, Distn and General Plt	-	-		Prorated on Production, Transmission, Distribution & General Plant in Service - Sch F 2.2 L.23
18	Property Insurance	-	-		Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch F 2.2 L.2, 4, 6, 18 - 19
	Revenue Related:				
19	Municipal Tax	263,893	-		Revenue-related
20	PUB Assessment	-	15,830		Revenue-related
21	All Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	263,893	15,830		
24	Total Operating & Maintenance Expenses	263,893	15,830		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Depreciation Expense

1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
Production																	
1	Diesel	3,945,929	1,803,117	2,142,812	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	3,945,929	1,803,117	2,142,812	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substn Struct & Eqpt	73,312	39,828	-	-	33,484	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	696	-	-	-	-	524	67	-	-	61	44	-	-	-	-	-
8	Poles	305,675	-	-	-	-	176,786	60,417	-	-	31,291	37,180	-	-	-	-	-
9	Primary Conductor & Equipment	44,658	-	-	-	-	39,611	5,046	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	97,876	-	-	-	-	-	-	35,333	62,543	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	5,597	-	-	-	-	-	-	-	-	3,263	2,334	-	-	-	-	-
13	Services	17,274	-	-	-	-	-	-	-	-	-	-	17,274	-	-	-	-
14	Meters	53,951	-	-	-	-	-	-	-	-	-	-	-	53,951	-	-	-
15	Street Lighting	26,970	-	-	-	-	-	-	-	-	-	-	-	-	26,970	-	-
16	Subtotal Distribution	626,009	39,828	-	-	33,484	216,922	65,530	35,333	62,543	34,615	39,557	17,274	53,951	26,970	-	-
17	Subtotal Prod Tran & Dist	4,571,938	1,842,945	2,142,812	-	33,484	216,922	65,530	35,333	62,543	34,615	39,557	17,274	53,951	26,970	-	-
18	General	717,239	290,424	339,320	-	3,054	21,149	6,228	2,704	4,787	3,383	3,800	1,778	2,870	837	36,904	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	17,405	7,016	8,158	-	127	826	249	135	238	132	151	66	205	103	-	-
21	Software - General	159,900	64,456	74,943	-	1,171	7,587	2,292	1,236	2,187	1,211	1,383	604	1,887	943	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	5,466,481	2,204,841	2,565,232	-	37,836	246,484	74,299	39,408	69,755	39,341	44,891	19,722	58,914	28,853	36,904	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Rate Base

1		2	3	4	5	Distribution											16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting Customer (\$)	Specifically Assigned Customer (\$)	
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
1	Average Net Book Value	95,513,749	38,869,723	45,257,995	-	1,035,405	3,914,077	1,159,823	749,704	1,327,039	620,896	702,300	417,884	756,310	302,355	400,239	-	
2	Cash Working Capital	62,057	25,254	29,405	-	673	2,543	754	487	862	403	456	272	491	196	260	-	
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Fuel Inventory - Diesel	5,700,591	-	5,700,591	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Inventory/Supplies	1,653,208	634,397	720,179	-	17,703	122,608	36,104	15,679	27,753	19,615	22,029	10,307	12,456	4,853	9,525	-	
	Deterred Charges:																	
	Foreign Exchange Loss and Regulatory																	
7	Costs	4,590,894	1,868,284	2,175,338	-	49,767	188,131	55,747	36,035	63,784	29,844	33,756	20,086	36,352	14,533	19,238	-	
8	Retired Asset Pool	12,632,077	5,140,677	5,985,551	-	136,936	517,652	153,391	99,151	175,506	82,116	92,882	55,267	100,025	39,988	52,933	-	
9	Total Rate Base	120,152,576	46,538,335	59,869,059	-	1,240,484	4,745,011	1,405,819	901,056	1,594,945	752,874	851,424	503,815	905,634	361,925	482,195	-	
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Rate Base Available for Equity Return	120,152,576	46,538,335	59,869,059	-	1,240,484	4,745,011	1,405,819	901,056	1,594,945	752,874	851,424	503,815	905,634	361,925	482,195	-	
12	Return on Debt	3,616,593	1,400,804	1,802,059	-	37,339	142,825	42,315	27,122	48,008	22,662	25,628	15,165	27,260	10,894	14,514	-	
13	Return on Equity	2,246,853	870,267	1,119,551	-	23,197	88,732	26,289	16,850	29,825	14,079	15,922	9,421	16,935	6,768	9,017	-	
14	Return on Rate Base	5,863,446	2,271,071	2,921,610	-	60,536	231,557	68,604	43,972	77,833	36,740	41,549	24,586	44,195	17,662	23,531	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch F 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch F 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch F 1.1,p2,L.16
13	Return on Equity	L.11 x Sch F 1.1,p2,L.19
14	Return on Rate Base	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Distribution										Accounting Customer	Specifically Assigned Customer
						Substations Demand	Primary Lines		Line Transformers		Secondary Lines		Services Customer	Meters Customer	Street Lighting Customer		
							Demand	Customer	Demand	Customer	Demand	Customer					
		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)	(Rural Cust)	(Rural Cust)			
	Amounts																
1	1.2 Domestic Diesel	-	6,194	24,737	6,194	6,025	6,025	2,232	5,767	2,232	5,767	2,232	2,232	2,232	-	2,232	-
2	1.2G Government Domestic Diesel	-	224	857	224	218	218	59	209	59	209	59	59	59	-	59	-
3	1.23 Churches, Schools & Com Halls	-	246	1,530	246	239	239	49	229	49	229	49	49	49	-	49	-
4	2.1 GS 0-10 kW	-	743	3,814	743	722	722	387	692	387	692	387	726	726	-	387	-
5	2.2 GS 10-100 kW	-	1,961	10,618	1,961	1,908	1,908	122	1,826	122	1,826	122	581	581	-	122	-
6	2.3 GS 110-1,000 kVa	-	156	2,483	156	151	151	6	145	6	145	6	51	51	-	6	-
7	2.4 GS Over 1,000 kVa	-	118	1,867	118	115	115	1	110	1	110	1	8	8	-	1	-
8	4.1 Street and Area Lighting	-	46	183	46	45	45	123	43	123	43	123	-	-	123	123	-
9	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	-	9,688	46,089	9,688	9,423	9,423	2,979	9,021	2,979	9,021	2,979	3,706	3,706	123	2,979	-
	Ratios																
11	1.2 Domestic Diesel	-	0.6393	0.5367	0.6393	0.6393	0.6393	0.7494	0.6393	0.7494	0.6393	0.7494	0.6023	0.6023	-	0.7494	-
12	1.2G Government Domestic Diesel	-	0.0231	0.0186	0.0231	0.0231	0.0231	0.0198	0.0231	0.0198	0.0231	0.0198	0.0159	0.0159	-	0.0198	-
13	1.23 Churches, Schools & Com Halls	-	0.0254	0.0332	0.0254	0.0254	0.0254	0.0164	0.0254	0.0164	0.0254	0.0164	0.0132	0.0132	-	0.0164	-
14	2.1 GS 0-10 kW	-	0.0767	0.0828	0.0767	0.0767	0.0767	0.1299	0.0767	0.1299	0.0767	0.1299	0.1960	0.1960	-	0.1299	-
15	2.2 GS 10-100 kW	-	0.0204	0.2304	0.0204	0.0204	0.0204	0.0409	0.0204	0.0409	0.0204	0.0409	0.1568	0.1568	-	0.0409	-
16	2.3 GS 110-1,000 kVa	-	0.0161	0.0539	0.0161	0.0161	0.0161	0.0020	0.0161	0.0020	0.0161	0.0020	0.0136	0.0136	-	0.0020	-
17	2.4 GS Over 1,000 kVa	-	0.0122	0.0405	0.0122	0.0122	0.0122	0.0003	0.0122	0.0003	0.0122	0.0003	0.0023	0.0023	-	0.0003	-
20	4.1 Street and Area Lighting	-	0.0048	0.0040	0.0048	0.0048	0.0048	0.0413	0.0048	0.0413	0.0048	0.0413	-	-	1.0000	0.0413	-
21	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)	
	Amounts			
1	1.2 Domestic Diesel	3,281,626	3,281,626	
2	1.2G Government Domestic Diesel	826,883	826,883	
3	1.23 Churches, Schools & Com Halls	210,070	210,070	
4	2.1 GS 0-10 kW	1,307,106	1,307,106	
5	2.2 GS 10-100 kW	3,170,396	3,170,396	
6	2.3 GS 110-1,000 kVa	262,528	262,528	
7	2.4 GS Over 1,000 kVa	205,566	205,566	
8	4.1 Street and Area Lighting	110,871	110,871	
9	4.1G Gov't Street and Area Lighting	8,864	8,864	
10	Total	9,383,911	9,383,911	
	Ratios			
11	1.2 Domestic Diesel	0.3497	0.3497	
12	1.2G Government Domestic Diesel	0.0881	0.0881	
13	1.23 Churches, Schools & Com Halls	0.0224	0.0224	
14	2.1 GS 0-10 kW	0.1393	0.1393	
15	2.2 GS 10-100 kW	0.3379	0.3379	
16	2.3 GS 110-1,000 kVa	0.0280	0.0280	
17	2.4 GS Over 1,000 kVa	0.0219	0.0219	
20	4.1 Street and Area Lighting	0.0118	0.0118	
21	4.1G Gov't Street and Area Lighting	0.0009	0.0009	
22	Total	1.0000	1.0000	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated

Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
Allocated Revenue Requirement Excluding Return																	
1	1.2 Domestic Diesel	21,713,165	5,227,588	14,614,673	-	77,203	478,414	164,218	71,309	147,957	75,801	99,783	40,439	77,950	-	540,328	-
2	1.2G Government Domestic Diesel	773,651	189,095	506,352	-	2,793	17,305	4,328	2,579	3,899	2,742	2,630	1,066	2,054	-	14,240	-
3	1.23 Churches, Schools & Com Halls	1,169,126	207,725	903,736	-	3,068	19,010	3,604	2,834	3,248	3,012	2,190	888	1,711	-	11,860	-
4	2.1 GS 0-10 kW	3,206,931	626,901	2,253,390	-	9,258	57,372	28,456	8,551	25,639	9,090	17,291	13,156	25,360	-	93,630	-
5	2.2 GS 10-100 kW	8,327,862	1,655,279	6,273,105	-	24,446	151,486	8,960	22,579	8,072	24,002	5,444	10,524	20,287	-	29,480	-
6	2.3 GS 110-1,000 kVa	1,629,157	131,342	1,467,121	-	1,940	12,020	441	1,792	398	1,904	268	915	1,764	-	1,452	-
7	2.4 GS Over 1,000 kVa	1,222,889	99,671	1,102,839	-	1,472	9,122	74	1,360	66	1,445	45	153	294	-	242	-
8	4.1 Street and Area Lighting	259,262	39,123	107,940	-	578	3,580	9,048	534	8,152	567	5,498	-	-	51,177	29,771	-
9	4.1G Gov't Street and Area Lighting	263	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-
Allocated Return on Debt and Equity																	
11	1.2 Domestic Diesel	3,458,350	1,451,954	1,568,112	-	38,702	148,040	51,413	28,112	58,329	23,489	31,138	14,808	26,619	-	17,634	-
12	1.2G Government Domestic Diesel	120,742	52,521	54,330	-	1,400	5,355	1,355	1,017	1,537	850	821	390	702	-	465	-
13	1.23 Churches, Schools & Com Halls	168,523	57,695	96,968	-	1,538	5,883	1,128	1,117	1,280	933	683	325	584	-	387	-
14	2.1 GS 0-10 kW	485,431	174,121	241,782	-	4,641	17,753	8,909	3,371	10,108	2,817	5,396	4,818	8,660	-	3,056	-
15	2.2 GS 10-100 kW	1,227,737	459,751	673,086	-	12,255	46,876	2,805	8,902	3,182	7,438	1,699	3,854	6,928	-	962	-
16	2.3 GS 110-1,000 kVa	201,250	36,480	157,418	-	972	3,719	138	706	157	590	84	335	602	-	47	-
17	2.4 GS Over 1,000 kVa	150,786	27,683	118,331	-	738	2,823	23	536	26	448	14	56	100	-	8	-
20	4.1 Street and Area Lighting	50,627	10,866	11,582	-	290	1,108	2,833	210	3,214	176	1,716	-	-	17,662	972	-
21	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total	5,863,446	2,271,071	2,921,610	-	60,536	231,557	68,604	43,972	77,833	36,740	41,549	24,586	44,195	17,662	23,531	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1	Description	18 Revenue Related		19 Basis of Proration
			Municipal Tax (\$)	PUB Assessment (\$)	
		Allocated Revenue Requirement Excluding Return			
1		1.2 Domestic Diesel	91,984	5,518	
2		1.2G Government Domestic Diesel	23,177	1,390	
3		1.23 Churches, Schools & Com Halls	5,888	353	
4		2.1 GS 0-10 kW	36,638	2,198	
5		2.2 GS 10-100 kW	88,866	5,331	
6		2.3 GS 110-1,000 kVa	7,359	441	
7		2.4 GS Over 1,000 kVa	5,762	346	
8		4.1 Street and Area Lighting	3,108	186	
9		4.1G Gov't Street and Area Lighting	248	15	
10		Total	263,030	15,779	
		Allocated Return on Debt and Equity			
11		1.2 Domestic Diesel	-	-	
12		1.2G Government Domestic Diesel	-	-	
13		1.23 Churches, Schools & Com Halls	-	-	
14		2.1 GS 0-10 kW	-	-	
15		2.2 GS 10-100 kW	-	-	
16		2.3 GS 110-1,000 kVa	-	-	
17		2.4 GS Over 1,000 kVa	-	-	
20		4.1 Street and Area Lighting	-	-	
21		4.1G Gov't Street and Area Lighting	-	-	
22		Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	
	Total Revenue Requirement																
1	1.2 Domestic Diesel	25,171,515	6,679,542	16,182,786	-	115,905	626,454	215,631	99,421	206,286	99,290	130,921	55,247	104,569	-	557,962	-
2	1.2G Government Domestic Diesel	894,393	241,616	560,683	-	4,193	22,660	5,683	3,596	5,436	3,592	3,450	1,456	2,756	-	14,705	-
3	1.23 Churches, Schools & Com Halls	1,337,649	265,420	1,000,704	-	4,606	24,893	4,733	3,951	4,528	3,945	2,874	1,213	2,295	-	12,247	-
4	2.1 GS 0-10 kW	3,692,362	801,021	2,495,172	-	13,900	75,125	37,365	11,923	35,746	11,907	22,686	17,974	34,020	-	96,686	-
5	2.2 GS 10-100 kW	9,555,598	2,115,030	6,946,191	-	36,701	198,362	11,765	31,481	11,255	31,440	7,143	14,378	27,215	-	30,442	-
6	2.3 GS 110-1,000 kVa	1,830,407	167,822	1,624,539	-	2,912	15,739	580	2,498	554	2,495	352	1,250	2,366	-	1,500	-
7	2.4 GS Over 1,000 kVa	1,373,675	127,354	1,221,170	-	2,210	11,944	97	1,896	92	1,893	59	208	394	-	250	-
8	4.1 Street and Area Lighting	309,889	49,989	119,522	-	867	4,688	11,881	744	11,366	743	7,213	-	-	68,839	30,742	-
9	4.1G Gov't Street and Area Lighting	263	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	44,165,752	10,447,794	30,150,766	-	181,293	979,867	287,733	155,509	275,264	155,305	174,698	91,727	173,615	68,839	744,534	-
Re-classification of Revenue-Related																	
11	1.2 Domestic Diesel	0	25,974	62,927	-	451	2,436	838	387	802	386	509	215	407	-	2,170	-
12	1.2G Government Domestic Diesel	(0)	6,824	15,836	-	118	640	161	102	154	101	97	41	78	-	415	-
13	1.23 Churches, Schools & Com Halls	0	1,244	4,691	-	22	117	22	19	21	18	13	6	11	-	57	-
14	2.1 GS 0-10 kW	(0)	8,515	26,523	-	148	799	397	127	380	127	241	191	362	-	1,028	-
15	2.2 GS 10-100 kW	0	21,057	69,155	-	365	1,975	117	313	112	313	71	143	271	-	303	-
16	2.3 GS 110-1,000 kVa	0	718	6,952	-	12	67	2	11	2	11	2	5	10	-	6	-
17	2.4 GS Over 1,000 kVa	(0)	569	5,454	-	10	53	0	8	0	8	0	1	2	-	1	-
20	4.1 Street and Area Lighting	(0)	537	1,284	-	9	50	128	8	122	8	78	-	-	740	330	-
21	4.1G Gov't Street and Area Lighting	(263)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total	(263)	65,438	192,824	-	1,135	6,137	1,666	974	1,594	973	1,012	602	1,140	740	4,311	-
Total Allocated Revenue Requirement																	
23	1.2 Domestic Diesel	25,171,515	6,705,516	16,245,713	-	116,356	628,890	216,469	99,808	207,088	99,676	131,430	55,462	104,975	-	560,132	-
24	1.2G Government Domestic Diesel	894,393	248,440	576,519	-	4,311	23,300	5,843	3,698	5,590	3,693	3,548	1,497	2,834	-	15,120	-
25	1.23 Churches, Schools & Com Halls	1,337,649	266,664	1,005,395	-	4,627	25,010	4,755	3,969	4,549	3,964	2,887	1,218	2,306	-	12,304	-
26	2.1 GS 0-10 kW	3,692,362	809,536	2,521,695	-	14,047	75,924	37,763	12,049	36,126	12,034	22,928	18,165	34,382	-	97,714	-
27	2.2 GS 10-100 kW	9,555,598	2,136,087	7,015,346	-	37,066	200,337	11,882	31,794	11,367	31,753	7,214	14,522	27,486	-	30,745	-
28	2.3 GS 110-1,000 kVa	1,830,407	168,540	1,631,491	-	2,925	15,807	582	2,509	557	2,505	353	1,256	2,376	-	1,506	-
29	2.4 GS Over 1,000 kVa	1,373,675	127,923	1,226,624	-	2,220	11,998	97	1,904	93	1,902	59	209	396	-	251	-
32	4.1 Street and Area Lighting	309,889	50,527	120,806	-	877	4,739	12,008	752	11,488	751	7,291	-	-	69,579	31,072	-
33	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total	44,165,488	10,513,232	30,343,589	-	182,429	986,005	289,399	156,483	276,858	156,277	175,709	92,329	174,755	69,579	748,845	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
Labrador Isolated

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Total Revenue Requirement			
1	1.2 Domestic Diesel	91,984	5,518	
2	1.2G Government Domestic Diesel	23,177	1,390	
3	1.23 Churches, Schools & Com Halls	5,888	353	
4	2.1 GS 0-10 kW	36,638	2,198	
5	2.2 GS 10-100 kW	88,866	5,331	
6	2.3 GS 110-1,000 kVa	7,359	441	
7	2.4 GS Over 1,000 kVa	5,762	346	
8	4.1 Street and Area Lighting	3,108	186	
9	4.1G Gov't Street and Area Lighting	248	15	
10	Total	263,030	15,779	
	Re-classification of Revenue-Related			
11	1.2 Domestic Diesel	(91,984)	(5,518)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
12	1.2G Government Domestic Diesel	(23,177)	(1,390)	
13	1.23 Churches, Schools & Com Halls	(5,888)	(353)	
14	2.1 GS 0-10 kW	(36,638)	(2,198)	
15	2.2 GS 10-100 kW	(88,866)	(5,331)	
16	2.3 GS 110-1,000 kVa	(7,359)	(441)	
17	2.4 GS Over 1,000 kVa	(5,762)	(346)	
20	4.1 Street and Area Lighting	(3,108)	(186)	
21	4.1G Gov't Street and Area Lighting	(248)	(15)	
22	Total	(263,030)	(15,779)	
	Total Allocated Revenue Requirement			
23	1.2 Domestic Diesel	-	-	
24	1.2G Government Domestic Diesel	-	-	
25	1.23 Churches, Schools & Com Halls	-	-	
26	2.1 GS 0-10 kW	-	-	
27	2.2 GS 10-100 kW	-	-	
28	2.3 GS 110-1,000 kVa	-	-	
29	2.4 GS Over 1,000 kVa	-	-	
32	4.1 Street and Area Lighting	-	-	
33	4.1G Gov't Street and Area Lighting	-	-	
34	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Expenses																
1	Operating & Maintenance	2,238,392	1,275,200	-	-	100,796	307,043	89,651	25,448	45,045	51,710	56,720	9,086	28,797	13,580	142,113	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	756,000	-	756,000	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	4,104,300	-	4,104,300	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,420,232	955,999	-	-	35,204	185,452	56,845	19,694	34,861	31,631	35,597	4,086	30,524	19,412	10,926	-
	Expense Credits																
8	Sundry	(7,321)	(4,171)	-	-	(330)	(1,004)	(293)	(83)	(147)	(169)	(186)	(30)	(94)	(44)	(465)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(61,423)	-	-	-	-	(35,524)	(12,140)	-	-	(6,288)	(7,471)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(432)	-	-	-	-	-	-	-	-	-	-	-	-	-	(432)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(69,176)	(4,171)	-	-	(330)	(36,528)	(12,434)	(83)	(147)	(6,457)	(7,656)	(30)	(94)	(44)	(897)	-
18	Subtotal Expenses	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
21	Return on Debt	807,239	515,833	2,820	-	80,989	93,023	26,427	11,363	20,114	15,514	16,789	2,004	12,497	7,038	2,828	-
22	Return on Equity	501,507	320,468	1,752	-	50,316	57,792	16,418	7,059	12,496	9,639	10,430	1,245	7,764	4,372	1,757	-
23	Total Revenue Requirement	9,758,496	3,063,329	4,864,871	-	266,976	606,783	176,908	63,482	112,368	102,037	111,880	16,391	79,488	44,358	156,727	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Functional Classification	20
		Municipal Tax (\$)	PUB Assessment (\$)		
	Expenses				
1	Operating & Maintenance	87,928	5,275	Carryforward from Sch F 2.4 L.24	
2	Fuels	-	-	Production - Energy	
3	Fuels-Diesel	-	-	Production - Energy	
4	Fuels-Gas Turbine	-	-	Production - Energy	
5	Power Purchases -CF(L)Co	-	-		
6	Power Purchases-Other	-	-	Carryforward from Sch F 4.4 L.21	
7	Depreciation	-	-	Carryforward from Sch F 2.5 L.23	
	Expense Credits				
8	Sundry	(288)	(17)	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24	
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch F 2.2 L.17	
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24	
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch F 2.4 L.24	
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch F 4.1 L.37	
13	Secondary Energy Revenues	-	-	Production - Energy	
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch F 4.1 L.16	
15	Application Fees	-	-	Accounting - Customer	
16	Meter Test Revenues	-	-	Meters - Customer	
17	Total Expense Credits	(288)	(17)		
18	Subtotal Expenses	87,641	5,257		
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch F 2.3 L.23	
20	Subtotal Revenue Requirement Ex. Return	87,641	5,257		
21	Return on Debt	-	-	Prorated on Rate Base - Sch F 2.6 L.9	
22	Return on Equity	-	-	Prorated on Rate Base - Sch F 2.6 L.11	
23	Total Revenue Requirement	87,641	5,257		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup

Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	20,618,739	20,618,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	20,618,739	20,618,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	2,430,420	66,299	-	-	2,364,122	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	452,466	-	-	-	-	341,137	43,459	-	-	39,568	28,302	-	-	-	-	-
8	Poles	9,870,601	-	-	-	-	5,708,642	1,950,944	-	-	1,010,434	1,200,581	-	-	-	-	-
9	Primary Conductor & Equipment	1,561,625	-	-	-	-	1,385,161	176,464	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,706,981	-	-	-	-	-	-	616,220	1,090,761	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	346,715	-	-	-	-	-	-	-	-	202,135	144,580	-	-	-	-	-
13	Services	220,006	-	-	-	-	-	-	-	-	-	-	220,006	-	-	-	-
14	Meters	517,483	-	-	-	-	-	-	-	-	-	-	-	517,483	-	-	-
15	Street Lighting	328,828	-	-	-	-	-	-	-	-	-	-	-	-	328,828	-	-
16	Subtotal Distribution	17,435,125	66,299	-	-	2,364,122	7,434,941	2,170,867	616,220	1,090,761	1,252,136	1,373,463	220,006	517,483	328,828	-	-
17	Subttl Prod, Trans, & Dist	38,053,864	20,685,037	-	-	2,364,122	7,434,941	2,170,867	616,220	1,090,761	1,252,136	1,373,463	220,006	517,483	328,828	-	-
18	General	3,153,661	1,876,333	-	-	142,013	446,618	130,404	37,016	65,522	75,216	82,504	13,216	42,644	19,753	222,420	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	165,343	89,876	-	-	10,272	32,305	9,432	2,677	4,739	5,441	5,968	956	2,248	1,429	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Plant	41,372,868	22,651,247	-	-	2,516,407	7,913,864	2,310,704	655,914	1,161,022	1,332,793	1,461,935	234,178	562,376	350,009	222,420	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup

Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch F 4.1 L.8
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch F 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch F 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch F 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch F 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Net Book Value

Line No.	1	Description	2 Total Amount (\$)	3 Production Demand (\$)	4 Production Energy (\$)	5 Transmission Demand (\$)	6	7	8	9	10	11	12	13	14	15	16	17	
							Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)			

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin		
						Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Production																
1	Diesel	822,932	822,932	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	13,430	13,430	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	836,362	836,362	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	453,948	1,779	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	-	8,823	-	-
9	Meters	19,049	-	-	-	-	-	-	-	-	-	-	-	19,049	-	-	-
10	Subtotal Distribution	472,997	1,779	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	19,049	8,823	-	-
11	Subttl Prod, Trans, & Dist	1,309,359	838,141	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	19,049	8,823	-	-
12	Customer Accounting	99,353	-	-	-	-	-	-	-	-	-	-	-	-	-	99,353	-
	Administrative & General:																
	Plant-Related:																
13	Production	40,074	40,074	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	45,672	174	-	-	6,193	19,476	5,687	1,614	2,857	3,280	3,598	576	1,356	861	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod,Trans, Distn & General Plt	3,364	1,842	-	-	205	643	188	53	94	108	119	19	46	28	18	-
18	Property Insurance	35,075	30,201	-	-	3,355	598	175	50	88	101	110	18	57	26	298	-
	Revenue Related:																
19	Municipal Tax	87,928	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	5,275	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related Prod, Trans, and Distn Expense-	601,806	358,056	-	-	27,100	85,227	24,885	7,064	12,503	14,353	15,744	2,522	8,138	3,769	42,444	-
22	Related	10,486	6,713	-	-	508	1,598	467	132	234	269	295	47	153	71	-	-
23	Subtotal Admin & General	829,680	437,059	-	-	37,360	107,542	31,400	8,913	15,777	18,111	19,866	3,182	9,749	4,756	42,760	-
24	Total Operating & Maintenance Expenses	2,238,392	1,275,200	-	-	100,796	307,043	89,651	25,448	45,045	51,710	56,720	9,086	28,797	13,580	142,113	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 19 Revenue Related		20 Basis of Functional Classification
		Municipal Tax	PUB Assessment	
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch F 4.1 L8
2	Other	-	-	Production - Demand, Energy ratios Sch F 4.1 L8
3	Subtotal Production	<u>-</u>	<u>-</u>	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch F 2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch F 2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.5
7	Subtotal Transmission	<u>-</u>	<u>-</u>	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch F 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	Subtotal Distribution	<u>-</u>	<u>-</u>	
11	Subttl Prod, Trans, & Dist	<u>-</u>	<u>-</u>	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch F 2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch F 2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch F 2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch F 2.2 L.17
17	Prod,Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch F 2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch F 2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	87,928	-	Revenue-related
20	PUB Assessment	-	5,275	Revenue-related
21	All Expense-Related Prod, Trans, and Distn Expense-	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	<u>87,928</u>	<u>5,275</u>	
24	Total Operating & Maintenance Expenses	<u>87,928</u>	<u>5,275</u>	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Production																
1	Diesel	831,373	831,373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	831,373	831,373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	27,473	296	-	-	27,177	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	7,258	-	-	-	-	5,472	697	-	-	635	454	-	-	-	-	-
8	Poles	229,935	-	-	-	-	132,982	45,447	-	-	23,538	27,967	-	-	-	-	-
9	Primary Conductor & Equipment	21,388	-	-	-	-	18,971	2,417	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	47,675	-	-	-	-	-	-	17,211	30,464	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	4,672	-	-	-	-	-	-	-	-	2,724	1,948	-	-	-	-	-
13	Services	3,309	-	-	-	-	-	-	-	-	-	-	3,309	-	-	-	-
14	Meters	27,371	-	-	-	-	-	-	-	-	-	-	-	27,371	-	-	-
15	Street Lighting	17,756	-	-	-	-	-	-	-	-	-	-	-	-	17,756	-	-
16	Subtotal Distribution	386,836	296	-	-	27,177	157,426	48,561	17,211	30,464	26,897	30,370	3,309	27,371	17,756	-	-
17	Subtotal Prod Tran & Dist	1,218,208	831,669	-	-	27,177	157,426	48,561	17,211	30,464	26,897	30,370	3,309	27,371	17,756	-	-
18	General	154,920	92,173	-	-	6,976	21,940	6,406	1,818	3,219	3,695	4,053	649	2,095	970	10,926	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	4,499	3,071	-	-	100	581	179	64	112	99	112	12	101	66	-	-
21	Software - General	42,606	29,087	-	-	950	5,506	1,698	602	1,065	941	1,062	116	957	621	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	1,420,232	955,999	-	-	35,204	185,452	56,845	19,694	34,861	31,631	35,597	4,086	30,524	19,412	10,926	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Rate Base

Line No.	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
		Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Distribution									Accounting Customer (\$)	Specifically Assigned Customer (\$)	
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin			
							Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
1	Average Net Book Value	24,686,846	15,872,117	-	-	2,503,217	2,821,144	800,796	347,953	615,906	470,370	508,805	60,096	384,383	216,109	85,951	-	
2	Cash Working Capital	16,039	10,312	-	-	1,626	1,833	520	226	400	306	331	39	250	140	56	-	
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Fuel Inventory - Diesel	93,674	-	93,674	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Inventory/Supplies	473,133	259,036	-	-	28,777	90,502	26,425	7,501	13,277	15,242	16,718	2,678	6,431	4,003	2,544	-	
	Deterred Charges:																	
	Foreign Exchange Loss and																	
7	Regulatory Costs	1,186,580	762,898	-	-	120,318	135,599	38,490	16,724	29,604	22,608	24,456	2,889	18,475	10,387	4,131	-	
8	Retired Asset Pool	362,309	232,942	-	-	36,738	41,404	11,753	5,107	9,039	6,903	7,467	882	5,641	3,172	1,261	-	
9	Total Rate Base	26,818,581	17,137,305	93,674	-	2,690,676	3,090,481	877,984	377,511	668,226	515,429	557,777	66,584	415,180	233,811	93,944	-	
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Rate Base Available for Equity Return	26,818,581	17,137,305	93,674	-	2,690,676	3,090,481	877,984	377,511	668,226	515,429	557,777	66,584	415,180	233,811	93,944	-	
12	Return on Debt	807,239	515,833	2,820	-	80,989	93,023	26,427	11,363	20,114	15,514	16,789	2,004	12,497	7,038	2,828	-	
13	Return on Equity	501,507	320,468	1,752	-	50,316	57,792	16,418	7,059	12,496	9,639	10,430	1,245	7,764	4,372	1,757	-	
14	Return on Rate Base	1,308,747	836,300	4,571	-	131,305	150,815	42,846	18,423	32,609	25,153	27,220	3,249	20,261	11,410	4,584	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch F 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch F 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and	
7	Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch F 1.1,p2,L.16
13	Return on Equity	L.11 x Sch F 1.1,p2,L.19
14	Return on Rate Base	

Basis of Allocation to Classes of Service

[illegible]

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.1 Domestic Diesel	609,244	609,244
2	1.12 Domestic All Electric	1,321,780	1,321,780
3	2.1 GS 0-10 kW	899,489	899,489
4	2.2 GS 10-100 kW	-	-
5	2.3 GS 110-1,000 kVa	277,254	277,254
6	4.1 Street and Area Lighting	18,925	18,925
7	Total	3,126,692	3,126,692
	Ratios		
8	1.1 Domestic Diesel	0.1949	0.1949
9	1.12 Domestic All Electric	0.4227	0.4227
10	2.1 GS 0-10 kW	0.2877	0.2877
11	2.2 GS 10-100 kW	-	-
12	2.3 GS 110-1,000 kVa	0.0887	0.0887
13	4.1 Street and Area Lighting	0.0061	0.0061
14	Total	1.0000	1.0000

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmsn Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Allocated Revenue Requirement Excluding Return																
1	1.1 Domestic Diesel	1,889,747	554,506	959,029	-	33,781	113,531	48,946	11,219	29,120	19,143	30,910	2,890	13,024	-	55,547	-
2	1.12 Domestic All Electric	3,816,627	1,057,198	2,172,394	-	64,405	216,453	56,699	21,390	33,733	36,498	35,806	3,348	15,087	-	64,346	-
3	2.1 GS 0-10 kW	2,046,179	489,511	1,259,419	-	29,821	100,224	23,141	9,904	13,768	16,900	14,614	6,518	29,373	-	26,262	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	626,992	119,082	456,772	-	7,255	24,381	778	2,409	463	4,111	491	387	1,743	-	883	-
6	4.1 Street and Area Lighting	70,204	6,731	12,687	-	410	1,378	4,498	136	2,676	232	2,841	-	-	32,948	5,105	-
7	Total	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
	Allocated Return on Debt and Equity																
8	1.1 Domestic Diesel	334,557	208,230	902	-	32,694	37,551	15,643	4,587	11,906	6,263	9,938	715	4,455	-	1,674	-
9	1.12 Domestic All Electric	605,009	397,002	2,043	-	62,332	71,594	18,121	8,745	13,792	11,940	11,512	828	5,161	-	1,939	-
10	2.1 GS 0-10 kW	286,771	183,823	1,185	-	28,861	33,150	7,396	4,049	5,629	5,529	4,699	1,611	10,048	-	791	-
11	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2.3 GS 110-1,000 kVa	63,877	44,718	430	-	7,021	8,064	249	985	189	1,345	158	96	596	-	27	-
13	4.1 Street and Area Lighting	18,533	2,528	12	-	397	456	1,438	56	1,094	76	913	-	-	11,410	154	-
14	Total	1,308,747	836,300	4,571	-	131,305	150,815	42,846	18,423	32,609	25,153	27,220	3,249	20,261	11,410	4,584	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Revenue Requirement Excluding Return			
1	1.1 Domestic Diesel	17,077	1,024	
2	1.12 Domestic All Electric	37,049	2,223	
3	2.1 GS 0-10 kW	25,213	1,512	
4	2.2 GS 10-100 kW	-	-	
5	2.3 GS 110-1,000 kVa	7,771	466	
6	4.1 Street and Area Lighting	530	32	
7	Total	87,641	5,257	
	Allocated Return on Debt and Equity			
8	1.1 Domestic Diesel	-	-	
9	1.12 Domestic All Electric	-	-	
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	-	-	
13	4.1 Street and Area Lighting	-	-	
14	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmsn Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
1	1.1 Domestic Diesel	2,224,304	762,736	959,931	-	66,474	151,082	64,589	15,806	41,025	25,406	40,847	3,604	17,480	-	57,221	-
2	1.12 Domestic All Electric	4,421,637	1,454,200	2,174,437	-	126,737	288,047	74,820	30,136	47,524	48,438	47,318	4,175	20,248	-	66,285	-
3	2.1 GS 0-10 kW	2,332,950	673,333	1,260,604	-	58,682	133,374	30,537	13,954	19,397	22,428	19,312	8,129	39,421	-	27,054	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	690,869	163,801	457,201	-	14,276	32,446	1,026	3,394	652	5,456	649	482	2,339	-	909	-
6	4.1 Street and Area Lighting	88,737	9,259	12,699	-	807	1,834	5,936	192	3,770	308	3,754	-	-	44,358	5,258	-
7	Total	9,758,496	3,063,329	4,864,871	-	266,976	606,783	176,908	63,482	112,368	102,037	111,880	16,391	79,488	44,358	156,727	-
Re-classification of Revenue-Related																	
8	1.1 Domestic Diesel	-	6,258	7,876	-	545	1,240	530	130	337	208	335	30	143	-	469	-
9	1.12 Domestic All Electric	0	13,032	19,486	-	1,136	2,581	670	270	426	434	424	37	181	-	594	-
10	2.1 GS 0-10 kW	(0)	7,803	14,608	-	680	1,546	354	162	225	260	224	94	457	-	314	-
11	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2.3 GS 110-1,000 kVa	0	1,977	5,517	-	172	392	12	41	8	66	8	6	28	-	11	-
13	4.1 Street and Area Lighting	0	59	81	-	5	12	38	1	24	2	24	-	-	283	34	-
14	Total	0	29,128	47,568	-	2,539	5,770	1,605	604	1,019	970	1,015	167	810	283	1,421	-
Total Allocated Revenue Requirement																	
15	1.1 Domestic Diesel	2,224,304	768,994	967,807	-	67,020	152,322	65,119	15,936	41,362	25,615	41,182	3,634	17,623	-	57,690	-
16	1.12 Domestic All Electric	4,421,637	1,467,231	2,193,923	-	127,872	290,629	75,490	30,406	47,950	48,872	47,742	4,213	20,430	-	66,879	-
17	2.1 GS 0-10 kW	2,332,950	681,136	1,275,212	-	59,363	134,919	30,891	14,115	19,621	22,688	19,536	8,223	39,878	-	27,367	-
18	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2.3 GS 110-1,000 kVa	690,869	165,777	462,718	-	14,448	32,837	1,039	3,435	660	5,522	657	488	2,367	-	920	-
20	4.1 Street and Area Lighting	88,737	9,318	12,780	-	812	1,846	5,973	193	3,794	310	3,778	-	-	44,641	5,292	-
21	Total	9,758,496	3,092,457	4,912,440	-	269,514	612,552	178,512	64,086	113,387	103,008	112,895	16,558	80,298	44,641	158,148	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Total Revenue Requirement			
1	1.1 Domestic Diesel	17,077	1,024	
2	1.12 Domestic All Electric	37,049	2,223	
3	2.1 GS 0-10 kW	25,213	1,512	
4	2.2 GS 10-100 kW	-	-	
5	2.3 GS 110-1,000 kVa	7,771	466	
6	4.1 Street and Area Lighting	530	32	
7	Total	87,641	5,257	
	Re-classification of Revenue-Related			
8	1.1 Domestic Diesel	(17,077)	(1,024)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
9	1.12 Domestic All Electric	(37,049)	(2,223)	
10	2.1 GS 0-10 kW	(25,213)	(1,512)	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	(7,771)	(466)	
13	4.1 Street and Area Lighting	(530)	(32)	
14	Total	(87,641)	(5,257)	
	Total Allocated Revenue Requirement			
15	1.1 Domestic Diesel	-	-	
16	1.12 Domestic All Electric	-	-	
17	2.1 GS 0-10 kW	-	-	
18	2.2 GS 10-100 kW	-	-	
19	2.3 GS 110-1,000 kVa	-	-	
20	4.1 Street and Area Lighting	-	-	
21	Total	-	-	

Functionalization & Classification Ratios

[illegible]

[illegible]

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	Island Isolated	Labrador Isolated	L'Anse au Loup	Labrador Interconnected
1	Sales+Losses for System Load Factor (MWh)	7,416,874	6,022	46,089	27,047	2,810,079
2	Hours in Year	8,760	8,760	8,760	8,760	8,760
3	Average Demand (kW)	846,675	687	5,261	3,088	320,785
4	Coincident Peak at Generation (kW)	1,683,676	1,809	9,688	6,105	480,169
1	System Load Factors	50.29%	38.00%	54.30%	50.57%	66.81%

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Holyrood Capacity Factor

	1	2	3	4	5
Line No.	Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1	2020 Actual	988,816,044	466	8,760	24.22%
2	2021 Actual	710,554,100	466	8,760	17.43%
3	2022 Actual	744,880,000	466	8,760	18.27%
4	2023 Actual	648,605,350	466	8,760	15.91%
5	2024 Actual	666,289,026	466	8,760	16.34%
6	5-Year Average	751,828,904	466	8,760	18.43%
7	Current Year	455,225,658	466	8,760	11.16%

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study
Total System
Power Purchases

Line No.	1	2	3	4	5	6	7	8	
		Total (\$)	Production Demand (\$)	Production & Transmission Energy (\$)	Transmission Export Demand (\$)	Transmission Network Demand (\$)	Rural Transmission Demand (\$)	Distribution Demand (\$)	Basis of Functional Classification
Island Interconnected:									
1	DLP Secondary	0		0					Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-					Production - Energy (Secondary)
3	Wheeling	960,000					960,000		Rural Transmission
4	Interruptible Demand	7,891,076	7,891,076						Production - Demand
5	Interruptible Energy	-		-					Production - Energy
6	Non-utility Generation excluding wind	36,232,222	18,012,022	18,220,200					Energy: System Load Factor
7	Wind Purchases	15,683,047	6,743,710	8,939,337					Production - Energy
8	Muskrat Falls Generation	269,134,556	133,794,098	135,340,458					Energy: System Load Factor
9	Total Exports	(40,178,593)	(19,973,870)	(20,204,723)					Energy: System Load Factor
10	Power Purchases - LTA Costs	46,146,683	22,940,770	23,205,914	-				Energy: System Load Factor
11	Power Purchases - LIL Costs	465,082,406	231,205,096	233,877,310	-				Energy: System Load Factor
12	Tariff Revenue	(18,337,593)	(9,116,116)	(9,221,477)	-				Energy: System Load Factor
13	Recapture to the Island	-	-	-	-				Energy: System Load Factor
14	Rate Mitigation	(501,963,983)	(249,539,930)	(252,424,053)	-				
15	Subtotal	280,649,821	141,956,856	137,732,965	-	-	960,000	-	
Labrador Interconnected:									
16	CF(L)Co	1,554,061	515,843	1,038,217					Energy: System Load Factor
17	Other	-	-						Labrador Lynx Interruptible
18									
19	Subtotal	1,554,061	515,843	1,038,217	-	-	-	-	
Isolated Systems:									
20	Mary's Harbour	309,793		309,793					Production - Energy
21	L'Anse au Loup	4,104,300		4,104,300					Production - Energy
22	Ramea Wind	177,100	76,153	100,947					Production - Energy
23	Subtotal	4,591,193	76,153	4,515,040	0	0	0	0	
24	Total	286,795,075	142,548,852	143,286,222	-	-	960,000	-	

Schedule G



NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total System Revenue Requirement

Line No.	1 Description	2 Total Amount (\$)	3 Island Interconnected (\$)	4 Island Isolated (\$)	5 Labrador Isolated (\$)	6 L'Anse au Loup (\$)	7 Labrador Interconnected (\$)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	156,361,556	120,418,337	5,763,854	15,269,542	2,238,392	12,671,431	Detailed Analysis
2	Fuels - No. 6 Fuel	65,010,009	65,010,009	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	22,311,830	2,016,430	2,124,200	17,415,200	756,000	-	Detailed Analysis
4	Fuels - Gas Turbine	18,989,062	18,829,333	-	-	-	159,728	
5	Fuel Supply Deferral	-	-	-	-	-	-	
6	Power Purchases -CF(L)Co	1,554,061	-	-	-	-	1,554,061	Detailed Analysis
7	Power Purchases - Other	65,357,539	60,766,346	177,100	309,793	4,104,300	-	Detailed Analysis
8	Power Purchases - MF	269,134,556	269,134,556	-	-	-	-	Detailed Analysis
9	Total Exports	(40,178,593)	(40,178,593)	-	-	-	-	Detailed Analysis
10	Power Purchases - LTA Costs	46,146,683	46,146,683	-	-	-	-	Detailed Analysis
11	Power Purchases - LIL Costs	465,082,406	465,082,406	-	-	-	-	Detailed Analysis
12	Rate Mitigation	-	-	-	-	-	-	
13	Tariff Revenue	(18,337,593)	(18,337,593)	-	-	-	-	Detailed Analysis
14	Depreciation	114,921,995	100,512,135	1,117,417	5,466,481	1,420,232	6,405,729	Detailed Analysis
	Expense Credits:	-	-	-	-	-	-	
15	Sundry	(511,404)	(393,846)	(18,852)	(49,941)	(7,321)	(41,444)	Total O&M Expenses
16	Greenhouse Gas Carbon Credits	(1,250,000)	(1,250,000)	-	-	-	-	Detailed Analysis
17	Building Rental Income	(6,000)	(6,000)	-	-	-	-	Detailed Analysis
18	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
19	Suppliers' Discounts	-	-	-	-	-	-	Total O&M Expenses
20	Pole Attachments	(1,635,600)	(1,196,656)	(20,860)	(107,593)	(61,423)	(249,068)	Detailed Analysis
21	Wheeling Revenues	-	-	-	-	-	-	Island Interconnected
22	Application Fees	(20,628)	(10,956)	(216)	(1,176)	(432)	(7,848)	Detailed Analysis
23	Meter Test Revenues	-	-	-	-	-	-	Weighted Customers
24	Total Expense Credits	(3,423,632)	(2,857,458)	(39,928)	(158,711)	(69,176)	(298,359)	
25	Subtotal Expenses	1,162,929,878	1,086,542,591	9,142,643	38,302,306	8,449,749	20,492,589	
26	Disposal Gain/Loss	-	-	-	-	-	-	Detailed Analysis
27	Subtotal Rev Req Excl Return	1,162,929,878	1,086,542,591	9,142,643	38,302,306	8,449,749	20,492,589	
28	Return on Debt	84,343,056	73,763,124	778,420	3,616,593	807,239	5,377,680	Rate Base
29	Return on Equity	52,399,174	45,826,260	483,603	2,246,853	501,507	3,340,951	Rate Base
30	Total Revenue Requirement	1,299,672,108	1,206,131,974	10,404,667	44,165,752	9,758,496	29,211,220	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total System
Return on Rate Base

Line No	1	2	3	4	5	6	7	8
	Total \$	Island Interconnected \$	Island Isolated \$	Labrador Isolated \$	L'Anse au Loup \$	Labrador Interconnected \$		Basis of Proration
	Rate Base:							
1	Average Net Book Value	2,404,120,916	2,102,740,030	21,518,581	95,513,749	24,686,846	159,661,709	Schedule G 2.3
2	Cash Working Capital	1,562,000	1,366,187	13,981	62,057	16,039	103,735	Prorated on Average Net Book Value - L. 1
3	Cash Working Capital - Muskrat Falls	115,124,000	115,124,000	-	-	-	-	Detailed Analysis
4	Fuel Inventory - No. 6 Fuel	53,963,965	53,963,965	-	-	-	-	Specifically Assigned - Holyrood
5	Fuel Inventory - Diesel	6,181,464	180,546	206,653	5,700,591	93,674	-	Detailed Fuel Analysis
6	Fuel Inventory - Gas Turbine	7,883,571	7,763,006	-	-	-	120,566	Detailed Fuel Analysis
7	Inventory/Supplies	44,722,000	39,481,123	217,603	1,653,208	473,133	2,896,934	Prorated on Total Plant in Service, Schedule G 2.2
8	Deferred Charges: Muskrat Falls	47,775	47,775	-	-	-	-	Detailed Analysis
	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	115,554,722	101,068,768	1,034,296	4,590,894	1,186,580	7,674,183	Prorated on Average Net Book Value - L. 1
10	Retired Asset Pool	52,934,464	28,866,724	2,870,021	12,632,077	362,309	8,203,333	Assigned by System
11	Total Rate Base	<u>2,802,094,876</u>	<u>2,450,602,123</u>	<u>25,861,135</u>	<u>120,152,576</u>	<u>26,818,581</u>	<u>178,660,460</u>	
12	Less: Rural Portion	-	-	-	-	-	-	Schedule G 2.6, L. 11
13	Rate Base Available for Equity Return	<u>2,802,094,876</u>	<u>2,450,602,123</u>	<u>25,861,135</u>	<u>120,152,576</u>	<u>26,818,581</u>	<u>178,660,460</u>	
	Corporate Targets:							
14	Capital Structure: Percent of Debt	74.50% ⁽¹⁾						
15	Return	4.05%						
16	Weighted Average Return: Debt	<u>3.01%</u>						
17	Capital Structure: Percent of Equity	21.75% ⁽¹⁾						
18	Return	8.60%						
19	Weighted Average Return: Equity	<u>1.87%</u>						
20	Weighted Average Cost of Capital	<u>4.88%</u>						
	Return on Rate Base by System (%):							
21	Return on Rate Base - Debt Component	-	3.01%	3.01%	3.01%	3.01%	3.01%	
22	Return on Rate Base - Equity Component	-	1.87%	1.87%	1.87%	1.87%	1.87%	
	Return on Rate Base (\$):							
23	Return on Debt	84,343,056	73,763,124	778,420	3,616,593	807,239	5,377,680	Schedule G 2.6, L.13
24	Return on Equity	52,399,174	45,826,260	483,603	2,246,853	501,507	3,340,951	Schedule G 2.6, L.14
25	Return on Rate Base (\$)	<u>136,742,230</u>	<u>119,589,384</u>	<u>1,262,023</u>	<u>5,863,446</u>	<u>1,308,747</u>	<u>8,718,630</u>	Schedule G 2.6, L.15
	Return on Total Rate Base (%):							
26	Return on Rate Base - Debt Component	3.01%	3.01%	3.01%	3.01%	3.01%	3.01%	L. 23 divided by L.11
27	Return on Rate Base - Equity Component	1.87%	1.87%	1.87%	1.87%	1.87%	1.87%	L. 24 divided by L.11
28	Return on Rate Base (%)	<u>4.88%</u>	<u>4.88%</u>	<u>4.88%</u>	<u>4.88%</u>	<u>4.88%</u>	<u>4.88%</u>	L. 25 divided by L.11

⁽¹⁾ Debt and equity weightings reflect a 0.74% funded ARO and 3.01% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credits (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	Total System						
1	Newfoundland Power	1,104,811,717	1,009,624,141	-	95,188,621	1,104,812,761	
2	RSP Activity	-	-	-	-	-	
3	Subtotal Newfoundland Power	1,104,811,717	1,009,624,141	-	95,188,621	1,104,812,761	1.09
4	Island Industrial	77,081,467	77,084,808	-	-	77,084,808	1.00
5	Unallocated RSP Hydraulic Variation	-	-	-	-	-	-
6	Labrador Industrial	9,171,998	9,172,200	-	-	9,172,200	1.00
7	CFB - Goose Bay Secondary	-	-	-	-	-	-
8	Rural Labrador Interconnected	21,931,248	20,039,020	-	1,889,304	21,928,324	1.09
	Rural Deficit Areas						
9	Island Interconnected	68,909,058	119,423,025	-	(50,513,967)	68,909,058	0.58
10	Island Isolated	1,717,949	10,404,402	-	(8,686,453)	1,717,949	0.17
11	Labrador Isolated	11,969,343	44,165,488	-	(32,196,145)	11,969,343	0.27
12	L'Anse au Loup	4,077,137	9,758,496	-	(5,681,359)	4,077,137	0.42
13	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
14	Subtotal	86,673,487	183,751,411	-	(97,077,924)	86,673,487	0.47
15	Total	1,299,669,917	1,299,671,580	-	-	1,299,671,580	1.00

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	Island Interconnected						
1	Newfoundland Power	1,104,811,717	1,009,624,141	-	95,188,621	1,104,812,761	
2	NLP RSP Activity	-				-	
3	Subtotal Newfoundland Power	1,104,811,717	1,009,624,141	-	95,188,621	1,104,812,761	1.09
4	Industrial - Firm	77,081,467	77,084,808	-		77,084,808	
5	Industrial - Non-Firm	-	-	-		-	
6	Industrial RSP Activity	-				-	
7	Subtotal Industrial	77,081,467	77,084,808	-	-	77,084,808	1.00
8	Unallocated RSP Hydraulic Variation	-					
	Rural						
9	1.1 Domestic	18,788,948	37,388,534	-	(18,599,586)	18,788,948	0.50
10	1.12 Domestic All Electric	23,929,645	42,858,448	-	(18,928,802)	23,929,645	0.56
11	1.3 Special	21,704	120,316	-	(98,612)	21,704	0.18
12	2.1 General Service 0-100 kW	12,084,583	18,726,443	-	(6,641,860)	12,084,583	0.65
13	2.3 General Service 110-1,000 kVa	7,645,700	11,511,869	-	(3,866,169)	7,645,700	0.66
14	2.4 General Service Over 1,000 kVa	5,260,869	7,187,262	-	(1,926,392)	5,260,869	0.73
15	4.1 Street and Area Lighting	1,177,608	1,630,154	-	(452,545)	1,177,608	0.72
16	Subtotal Rural	68,909,058	119,423,025	-	(50,513,967)	68,909,058	0.58
17	Total Island Interconnected	1,250,802,242	1,206,131,974	-	44,674,653	1,250,806,627	1.04

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		(\$)	(\$)	(\$)	(\$)	(\$)	
	Island Isolated						
1	1.2 Domestic Diesel	809,510	7,704,844		(6,895,334)	809,510	0.11
2	1.2G Government Domestic Diesel	-	55,464		(55,464)	-	-
3	1.23 Churches, Schools & Com Halls	54,843	367,319		(312,476)	54,843	0.15
4	2.1 General Service 0-10 kW	285,054	823,425		(538,370)	285,054	0.35
5	2.2 GS 10-100 kW	535,299	1,290,296		(754,997)	535,299	0.41
6	2.3 GS 110-1,000 kVa	-	-		-	-	-
7	2.4 General Service Over 1,000 kVa	-	-		-	-	-
8	4.1 Street and Area Lighting	26,859	163,053		(136,195)	26,859	0.16
9	4.1G Gov't Street and Area Lighting	6,384	-		6,384	6,384	-
10	Total	1,717,949	10,404,402		(8,686,453)	1,717,949	0.17

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Isolated							
1	1.2 Domestic Diesel	4,669,502	25,171,515		(20,502,013)	4,669,502	0.19
2	1.2G Government Domestic Diesel	945,104	894,393		50,711	945,104	1.06
3	1.23 Churches, Schools & Com Halls	328,742	1,337,649		(1,008,907)	328,742	0.25
4	2.1 General Service 0-10 kW	1,505,530	3,692,362		(2,186,832)	1,505,530	0.41
5	2.2 GS 10-100 kW	3,760,679	9,555,598		(5,794,920)	3,760,679	0.39
6	2.3 GS 110-1,000 kVa	364,087	1,830,407		(1,466,319)	364,087	0.20
7	2.4 General Service Over 1,000 kVa	245,160	1,373,675		(1,128,515)	245,160	0.18
8	4.1 Street and Area Lighting	144,155	309,889		(165,734)	144,155	0.47
9	4.1G Gov't Street and Area Lighting	6,384	-		6,384	6,384	-
10	Total	11,969,343	44,165,488		(32,196,145)	11,969,343	0.27

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		(\$)	(\$)	(\$)	(\$)	(\$)	
	L'Anse au Loup						
1	1.1 Domestic	828,511	2,224,304		(1,395,792)	828,511	0.37
2	1.12 Domestic All Electric	1,782,547	4,421,637		(2,639,090)	1,782,547	0.40
3	2.1 General Service 0-100 kW	1,046,118	2,332,950		(1,286,832)	1,046,118	0.45
4	2.2 General Service 10-100 kW	-	-		-	-	-
5	2.3 General Service 110-1,000 kVa	354,037	690,869		(336,832)	354,037	0.51
6	4.1 Street and Area Lighting	65,923	88,737		(22,814)	65,923	0.74
7	Total L'Anse Au Loup	4,077,137	9,758,496		(5,681,359)	4,077,137	0.42

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected						
1	Labrador Industrial Firm	9,171,998	9,172,200	-	-	9,172,200	1.00
2	Labrador Industrial Non-Firm	-	-	-	-	-	-
3	Subtotal Industrial	9,171,998	9,172,200	-	-	9,172,200	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
	Rural						
5	1.1 Domestic	104,601	206,448	-	19,464.14	225,912	0.46
6	1.1A Domestic All Electric	11,621,732	12,172,687	-	1,147,656	13,320,344	0.87
7	2.1 General Service 0-10 kW	297,862	302,668	-	28,536	331,204	0.90
8	2.2 General Service 10-100 kW	2,454,188	1,963,429	-	185,115	2,148,543	1.14
9	2.3 General Service 110-1,000 kVa	4,196,072	2,864,082	-	270,029	3,134,111	1.34
10	2.4 General Service Over 1,000 kVa	2,863,986	2,090,121	-	197,059	2,287,181	1.25
11	4.1 Street and Area Lighting	392,808	439,585	-	41,445	481,029	0.82
12	Subtotal Rural	21,931,248	20,039,020	-	1,889,304	21,928,324	
13	Total Labrador Interconnected	31,103,246	29,211,220	-	1,889,304	31,100,524	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total System
Rural Deficit Allocation

Line No.	1	2			
			Deficit Allocation Allocated on Revenue Requirement	Island Interconnected	Labrador Interconnected
			(\$)	(\$)	(\$)
	ALLOCATION OF DEFICIT:				
1	Rural Deficit Classified	97,077,924			
2	Allocated Totals	97,077,924	95,188,621	1,889,304	
	CUSTOMER DEFICIT ALLOCATION:				
		Amount	Revenue Requirement	Percent	
	Island Interconnected:				
3	Newfoundland Power	95,188,621	1,009,624,141	98.1%	
	Labrador Interconnected:				
4	Rural Labrador Interconnected	1,889,304	20,039,020	1.9%	
5	Total	97,077,924		100.0%	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line No.		Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)
	Island Interconnected										
1	Newfoundland Power	33.54	-	0.07340	-	228,471.85	36.70	-	0.08032	-	250,012.46
2	Industrial - Firm	28.88	-	0.07341	-	5,735.41	28.88	-	0.07341	-	5,735.41
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
	Rural										
4	1.1 Domestic	-	0.21186	0.08072	0.29258	40.25	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.18261	0.08081	0.26342	40.29	-	-	-	-	-
6	1.3 Special	-	0.26713	0.08022	0.34735	40.00	-	-	-	-	-
7	2.1 General Service 0-10 kW	42.93	-	0.08106	-	59.32	-	-	-	-	-
8	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	41.14	-	0.08079	-	77.68	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	31.48	-	0.07845	-	77.54	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.21299	0.08131	0.29430	80.37	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line No.		Demand		Non-Demand			Demand		Non-Demand		
		Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Demand & Energy (\$/kWh)	Customer (\$/Bill)
Isolated Systems:											
1	1.2 Domestic Diesel	-	0.40411	0.70486	1.10897	59.48					
2	2.1 General Service 0-10 kW	-	0.28507	0.70790	0.99296	60.91					
3	2.2 GS 10-100 kW	70.74	-	0.70018	-	74.94					
4	2.3 GS 110-1,000 kVa	18.45	-	0.68590	-	92.09					
5	2.4 General Service Over 1,000 kVa	25.89	-	0.68603	-	92.10					
6	Subtotal Metered Demand Classes	57.16	-	0.69628	-	75.82					
7	4.1 Street and Area Lighting	-	0.41845	0.71159	1.13004	125.84					
Island Isolated											
8	1.2 Domestic Diesel	-	0.93339	0.81837	1.75176	98.56	-	-	-	-	-
9	2.1 General Service 0-10 kW	-	0.49421	0.82234	1.31655	108.37	-	-	-	-	-
10	2.2 GS 10-100 kW	176.03	-	0.82560	-	150.09	-	-	-	-	-
11	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-
12	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-
13	4.1 Street and Area Lighting	-	0.88062	0.82195	1.70257	258.93	-	-	-	-	-
Labrador Isolated											
14	1.2 Domestic Diesel	-	0.31708	0.68619	1.00327	49.95	-	-	-	-	-
15	2.1 General Service 0-10 kW	-	0.25281	0.69024	0.94305	53.23	-	-	-	-	-
16	2.2 GS 10-100 kW	61.91	-	0.68978	-	70.62	-	-	-	-	-
17	2.3 GS 110-1,000 kVa	18.45	-	0.68590	-	92.09	-	-	-	-	-
18	2.4 General Service Over 1,000 kVa	25.89	-	0.68603	-	92.10	-	-	-	-	-
19	4.1 Street and Area Lighting	-	0.32940	0.69032	1.01972	89.05	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line No.		Demand			Non-Demand		Demand			Non-Demand	
		Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Demand & Energy (\$/kWh)	Customer (\$/Bill)
	L'Anse au Loup										
1	1.1 Domestic	-	0.20909	0.19648	0.40557	45.67	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.17611	0.19663	0.37274	45.70	-	-	-	-	-
3	2.1 General Service 0-10 kW	39.65	-	0.19714	-	62.03	-	-	-	-	-
4	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	24.22	-	0.19724	-	77.75	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.19152	0.19613	0.38764	139.21	-	-	-	-	-
	Labrador Interconnected										
7	Labrador Industrial - Firm	2.40	-	-	-	-	2.40	-	-	-	-
8	Labrador Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
9	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-
	Rural										
10	1.1 Domestic	-	0.02547	0.00153	0.02700	38.32	-	0.02788	0.00167	0.02955	41.93
11	1.1A Domestic All Electric	-	0.02181	0.00155	0.02336	38.79	-	0.02387	0.00169	0.02556	42.45
12	Subtotal Domestic	-	0.02184	0.00155	0.02338	38.78	-	0.02390	0.00169	0.02559	42.44
13	2.1 General Service 0-10 kW	-	0.01650	0.00156	0.01806	43.34	-	0.01806	0.00171	0.01977	47.43
14	2.2 General Service 10-100 kW	5.33	-	0.00156	-	57.22	5.83	-	0.00171	-	62.61
15	2.3 General Service 110-1,000 kVa	5.43	-	0.00156	-	75.01	5.95	-	0.00171	-	82.08
16	2.4 General Service Over 1,000 kVa	7.81	-	0.00154	-	75.75	8.55	-	0.00168	-	82.89
17	4.1 Street and Area Lighting	-	0.02190	0.00154	0.02344	87.30	-	0.02396	0.00169	0.02565	95.53

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	Island Interconnected								
1	Newfoundland Power	1,009,624,141	565,425,000	441,457,479	2,741,662	1,104,812,761	618,733,972	483,078,639	3,000,150
2	Industrial - Firm	77,084,808	31,644,908	45,026,951	412,949	77,084,808	31,644,908	45,026,951	412,949
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-
	Rural								
4	1.1 Domestic	37,388,534	23,054,202	8,783,452	5,550,880	-	-	-	-
5	1.12 Domestic All Electric	42,858,448	26,789,919	11,855,521	4,213,008	-	-	-	-
6	1.3 Special	120,316	92,160	27,676	480	-	-	-	-
7	2.1 General Service 0-10 kW	18,726,443	10,657,499	5,903,949	2,164,995	-	-	-	-
8	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	11,511,869	7,034,411	4,399,620	77,838	-	-	-	-
10	2.4 General Service Over 1,000 kVa	7,187,262	4,019,712	3,160,106	7,444	-	-	-	-
11	4.1 Street and Area Lighting	1,630,154	442,333	168,871	1,018,950	-	-	-	-
12	Subtotal Rural	119,423,025	72,090,235	34,299,195	13,033,595				
13	Total Island Interconnected	1,206,131,974	669,160,143	520,783,625	16,188,206				

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	Isolated Systems:								
1	1.2 Domestic Diesel	35,531,185	12,225,414	21,323,744	1,982,027				
2	2.1 General Service 0-10 kW	4,515,787	1,202,109	2,985,134	328,544				
3	2.2 GS 10-100 kW	10,845,894	3,018,652	7,711,419	115,823				
4	2.3 GS 110-1,000 kVa	1,830,407	192,285	1,631,491	6,630				
5	2.4 General Service Over 1,000 kVa	1,373,675	145,946	1,226,624	1,105				
6	Subtotal Metered Demand Classes	14,049,976	3,356,883	10,569,534	123,559				
7	4.1 Street and Area Lighting	472,942	87,340	148,522	237,081				
8	Total Isolated Systems	54,569,890	16,871,746	35,026,934	2,671,210				
	Island Isolated								
9	1.2 Domestic Diesel	8,127,627	3,987,492	3,496,117	644,019	-	-	-	-
10	2.1 General Service 0-10 kW	823,425	278,519	463,439	81,467	-	-	-	-
11	2.2 GS 10-100 kW	1,290,296	581,615	696,073	12,608	-	-	-	-
12	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-
14	4.1 Street and Area Lighting	163,053	29,695	27,716	105,642	-	-	-	-
15	Total Island Isolated	10,404,402	4,877,320	4,683,345	843,737				
	Labrador Isolated								
16	1.2 Domestic Diesel	27,403,557	8,237,923	17,827,627	1,338,008	-	-	-	-
17	2.1 General Service 0-10 kW	3,692,362	923,590	2,521,695	247,077	-	-	-	-
18	2.2 GS 10-100 kW	9,555,598	2,437,037	7,015,346	103,215	-	-	-	-
19	2.3 GS 110-1,000 kVa	1,830,407	192,285	1,631,491	6,630	-	-	-	-
20	2.4 General Service Over 1,000 kVa	1,373,675	145,946	1,226,624	1,105	-	-	-	-
21	4.1 Street and Area Lighting	309,889	57,645	120,806	131,438	-	-	-	-
22	Total Labrador Isolated	44,165,488	11,994,426	30,343,589	1,827,473				

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)	Total (\$)	Demand (\$)	Energy (\$)	Customer (\$)
	L'Anse au Loup								
1	1.1 Domestic	2,224,304	1,029,886	967,807	226,610	-	-	-	-
2	1.12 Domestic All Electric	4,421,637	1,965,011	2,193,923	262,703	-	-	-	-
3	2.1 General Service 0-10 kW	2,332,950	912,221	1,275,212	145,517	-	-	-	-
4	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	690,869	222,020	462,718	6,131	-	-	-	-
6	4.1 Street and Area Lighting	88,737	12,479	12,780	63,478	-	-	-	-
7	Total L'Anse au Loup	9,758,496	4,141,617	4,912,440	704,439				
	Labrador Interconnected								
8	Labrador Industrial - Firm	9,172,200	9,127,445	-	44,754	9,172,200	9,127,445	-	44,754
9	Labrador Industrial - Non-Firm	-	-	-	-	-	-	-	-
10	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-
	Rural								
11	1.1 Domestic	206,448	57,902	3,472	145,073	225,912	63,361	3,800	158,751
12	1.1A Domestic All Electric	12,172,687	6,989,193	495,604	4,687,891	13,320,344	7,648,142	542,330	5,129,872
13	Subtotal Domestic	12,379,135	7,047,094	499,076	4,832,965	13,546,255	7,711,503	546,129	5,288,623
14	2.1 General Service 0-10 kW	302,668	72,906	6,891	222,871	331,204	79,780	7,541	243,883
15	2.2 General Service 10-100 kW	1,963,429	1,326,045	116,569	520,815	2,148,543	1,451,066	127,559	569,918
16	2.3 General Service 110-1,000 kVa	2,864,082	2,445,074	242,120	176,888	3,134,111	2,675,598	264,948	193,565
17	2.4 General Service Over 1,000 kVa	2,090,121	1,862,739	221,928	5,454	2,287,181	2,038,361	242,852	5,968
18	4.1 Street and Area Lighting	439,585	21,166	1,493	416,925	481,029	23,162	1,634	456,234
19	Subtotal Rural	20,039,020	12,775,026	1,088,077	6,175,917	21,928,324	13,979,471	1,190,663	6,758,190
20	Total Labrador Interconnected	29,211,220	21,902,471	1,088,077	6,220,671	31,100,524	23,106,916	1,190,663	6,802,945

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Island Interconnected				
1	Newfoundland Power	16,860,014	6,014,582	1	12
2	Industrial - Firm	1,095,600	613,371	6	72
3	Industrial - Non-Firm	-	-	-	-
	Rural				
4	1.1 Domestic	-	108,816	11,494	137,927
5	1.12 Domestic All Electric	-	146,706	8,714	104,563
6	1.3 Special	-	345	1	12
7	2.1 General Service 0-10 kW	248,253	72,837	3,042	36,498
8	2.2 General Service 10-100 kW	-	-	-	-
9	2.3 General Service 110-1,000 kVa	171,006	54,457	84	1,002
10	2.4 General Service Over 1,000 kVa	127,708	40,282	8	96
11	4.1 Street and Area Lighting	-	2,077	1,057	12,678
12	Subtotal Rural	546,967	425,520	24,398	292,776
13	Total Island Interconnected	18,502,582	7,053,473	24,405	292,860

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Isolated Systems:				
1	1.2 Domestic Diesel	-	30,253	2,900	33,323
2	2.1 General Service 0-10 kW	-	4,217	449	5,394
3	2.2 GS 10-100 kW	42,671	11,014	129	1,546
4	2.3 GS 110-1,000 kVa	10,423	2,379	6	72
5	2.4 General Service Over 1,000 kVa	5,638	1,788	1	12
6	Subtotal Metered Demand Classes	58,732	15,180	136	1,630
7	4.1 Street and Area Lighting	-	209	157	1,884
8	Total Isolated Systems	58,732	49,858	3,642	42,230
	Island Isolated				
9	1.2 Domestic Diesel	-	4,272	560	6,534
10	2.1 General Service 0-10 kW	-	564	63	752
11	2.2 GS 10-100 kW	3,304	843	7	84
12	2.3 GS 110-1,000 kVa	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-
14	4.1 Street and Area Lighting	-	34	34	408
15	Total Island Isolated	3,304	5,712	663	7,778
	Labrador Isolated				
16	1.2 Domestic Diesel	-	25,980	2,340	26,789
17	2.1 General Service 0-10 kW	-	3,653	387	4,642
18	2.2 GS 10-100 kW	39,367	10,170	122	1,462
19	2.3 GS 110-1,000 kVa	10,423	2,379	6	72
20	2.4 General Service Over 1,000 kVa	5,638	1,788	1	12
21	4.1 Street and Area Lighting	-	175	123	1,476
22	Total Labrador Isolated	55,428	44,146	2,979	34,453

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Demands, Sales, & Number of Bills

Line No.	Rate Class	1	2	3	4	5
		Units				
		Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)	
L'Anse au Loup						
1	1.1 Domestic	-	4,926	414	4,962	
2	1.12 Domestic All Electric	-	11,158	479	5,748	
3	2.1 General Service 0-10 kW	23,004	6,468	196	2,346	
4	2.2 General Service 10-100 kW	-	-	-	-	
5	2.3 General Service 110-1,000 kVa	9,166	2,346	7	79	
6	4.1 Street and Area Lighting	-	65	38	456	
7	Total L'Anse au Loup	32,170	24,963	1,133	13,591	
Labrador Interconnected						
8	Labrador Industrial - Firm	3,804,000	1,902,365	-	-	
9	Labrador Industrial - Non-Firm	-	-	-	-	
10	CFB - Goose Bay Secondary	-	-	-	-	
Rural						
11	1.1 Domestic	-	2,273	316	3,786	
12	1.1A Domestic All Electric	-	320,448	10,070	120,840	
13	Subtotal Domestic	-	322,721	10,386	124,626	
14	2.1 General Service 0-10 kW	-	4,418	429	5,142	
15	2.2 General Service 10-100 kW	248,712	74,799	759	9,102	
16	2.3 General Service 110-1,000 kVa	449,945	155,037	197	2,358	
17	2.4 General Service Over 1,000 kVa	238,486	144,227	6	72	
18	4.1 Street and Area Lighting	-	967	398	4,776	
19	Subtotal Rural	937,142	702,170	12,173	146,076	
20	Total Labrador Interconnected	4,741,142	2,604,535	12,173	146,076	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Rate Calculations for Newfoundland Power

Line No.	1	2	3
	Description	Amount	Source
	Newfoundland Power:		
	Demand:		
1	Rate (\$/kW/mo.)	\$5.50	
2	Billing Units (kW)	16,860,014	Sch G 1.3.2, pg 1, Ln 1, Col 2
3	Demand Revenue	\$92,730,079	Ln 1 * Ln 2
	Energy (First Block):		
4	Total Revenue Requirement	\$1,104,812,761	Sch G 1.2, pg 1, Ln 1, Col 6
5	Less: Demand Revenue	\$92,730,079	Ln 3
6	Less: Second Block Energy Revenue (winter)	\$138,546,777	Ln 11 * Ln 13
7	Less: Second Block Energy Revenue (non-winter)	\$51,084,861	Ln 14 * Ln 16
8	First Block Energy Revenue	<u>\$822,451,044</u>	Ln 4 - Ln 5 - Ln 6 - Ln 7
9	First Block Energy Consumed (MWh)	3,000,000	
10	Rate (¢/kWh)	27.415	Ln 8 / Ln 9
	Energy (Second Block - Winter):		
11	Energy Consumption (MWh)	1,546,626	
12	Energy Revenue (winter)	\$138,546,777	
13	Rate (¢/kWh)	8.958	
	Energy (Second Block - Non-winter):		
14	Energy Consumption (MWh)	1,467,956	
15	Energy Revenue (non-winter)	\$51,084,861	
16	Rate (¢/kWh)	3.480	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Value of Newfoundland Power Thermal Generation Credit

Line No.	Description	Amount	Source
1	Island Interconnected System:		
2	Generation demand costs (\$)	560,623,656	Sch G 2.1A, C. 3, Ln 31
3	Coincident peak (kW)	1,644,378	Sch G 3.1A, C. 3, Ln 13
4	Generation demand costs (\$/kW)	<u>340.93</u>	Ln 2 / Ln 3
5	NP thermal generation capacity credit (kW)	<u>39,299</u>	⁽¹⁾
6	Gross value of credit to NP (\$)	<u>13,398,208</u>	Ln 4 x Ln 5
7	Less NP's cost share:		
8	Percentage	89.00%	Sch G 3.1A, C. 5, Ln 14
9	Amount (\$)	<u>(11,924,600)</u>	Ln 6 x Ln 8
10	Net value of credit to NP (\$)	<u><u>1,473,608</u></u>	Ln 6 - Ln 9

⁽¹⁾ NP gas turbine and diesel generation capacity (kW)
+ System reserve
NP thermal generation capacity credit (kW)

44,500
1.132
39,299

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Calculation of Firming Up Charge

	1	2	3	4
Line No.	Description	Total	Gas Turbine	Transmission & Terminals
1	Operating & Maintenance	18,091,849	4,264,846	13,827,003
2	O&M Overhead	15,874,399	4,901,340	10,973,058
3	Depreciation	24,638,245	6,720,131	17,918,114
4	Return	40,542,173	7,359,677	33,182,497
5	Total	99,146,666	23,245,994	75,900,672
6	Capacity (kW)		248,500	1,797,100
7	Cost (\$/kW)	\$135.78	\$93.55	\$42.24
8	Transmission coincident peak ⁽¹⁾	1,435,869		
9	Newfoundland Power Sales (MWh)	6,014,582		
10	Rate (\$/kWh)	\$0.03242		

⁽¹⁾ Newfoundland Power Transmission Coincident Peak adjusted for thermal credit in compliance with PU.8(2007).

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Calculation of Transmission Wheeling Charge

	1	2
Line No.	Description	
1	Island Interconnected Transmission Revenue Requirement	75,818,020
2	Transmission Energy Output (MWh)	7,089,578
3	Rate (\$/kWh)	\$0.01069

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution	Primary Lines Demand (\$)	Customer (\$)	Line Transformers Demand (\$)	Customer (\$)	Secondary Lines Demand (\$)	Customer (\$)	Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)											
	Expenses																	
1	Operating & Maintenance	120,418,337	54,298,912	19,682,217	24,800,061	3,485,290	2,469,383	4,736,713	1,292,255	394,987	699,159	684,343	776,616	228,066	610,124	194,602	3,119,143	532,535
2	Fuels-No. 6 Fuel	65,010,009	-	65,010,009	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	2,016,430	2,016,430	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	18,829,333	18,829,333	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Supply Deferral	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Power Purchases-Other	60,766,346	32,646,808	27,159,537	-	960,000	-	-	-	-	-	-	-	-	-	-	-	-
8	Power Purchases-MF	269,134,556	133,794,098	135,340,458	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Exports	(40,178,593)	(19,973,870)	(20,204,723)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Power Purchases - LTA Costs	46,146,683	22,940,770	23,205,914	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Power Purchases - LIL Costs	465,082,406	231,205,096	233,877,310	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate Mitigation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Tariff Revenue	(18,337,593)	(9,116,116)	(9,221,477)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Depreciation	100,512,135	52,319,167	16,798,496	17,918,114	2,388,332	1,960,361	3,655,270	1,041,484	320,771	567,792	534,749	618,155	141,706	598,613	233,200	375,105	1,040,820
	Expense Credits																	
15	Sundry	(393,846)	(177,593)	(64,374)	(81,112)	(11,399)	(8,076)	(15,492)	(4,227)	(1,292)	(2,287)	(2,238)	(2,540)	(746)	(1,996)	(636)	(10,202)	(1,742)
16	Greenhouse Gas Carbon Credits	(1,250,000)	(621,409)	(628,591)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Building Rental Income	(6,000)	(2,281)	(1,234)	(1,540)	(232)	(120)	(240)	(65)	(20)	(35)	(35)	(39)	(12)	(18)	(10)	-	(119)
18	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Pole Attachments	(1,196,656)	-	-	-	-	-	(692,084)	(236,521)	-	-	(122,499)	(145,552)	-	-	-	-	-
21	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Application Fees	(10,956)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10,956)	-
24	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Expense Credits	(2,857,458)	(801,283)	(694,199)	(82,652)	(11,631)	(8,196)	(707,816)	(240,813)	(1,312)	(2,322)	(124,772)	(148,131)	(757)	(2,014)	(646)	(21,158)	(1,860)
26	Subtotal Expenses	1,086,542,591	518,159,345	490,953,541	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495
27	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Subtotal Revenue Requirement Ex. Return	1,086,542,591	518,159,345	490,953,541	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495
29	Return on Debt	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863
30	Return on Equity	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646
31	Total Revenue Reqmt	1,206,131,974	560,623,656	519,940,005	75,818,020	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	3,152,004

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	Description	19	20	21
		Revenue Related Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	1,436,329	977,601	Carryforward from Sch G 2.4 L.30
2	Fuels-No. 6 Fuel	-	-	Production - Demand, Energy ratios Sch G 4.1 L.10
3	Fuels-Diesel	-	-	Production - Demand, Energy ratios Sch G 4.1 L.12
4	Fuels-Gas Turbine	-	-	Production - Demand, Energy ratios Sch G 4.1 L.11
5	Fuel Supply Deferral	-	-	
6	Power Purchases -CF(L)Co	-	-	
7	Power Purchases-Other	-	-	Carryforward from Sch G 4.4 L.1 - L.7
8	Power Purchases-MF	-	-	Carryforward from Sch G 4.4 L.8
9	Total Exports	-	-	
10	Power Purchases - LTA Costs	-	-	
11	Power Purchases - LIL Costs	-	-	Carryforward from Sch G 4.4 L.10
12	Rate Mitigation	-	-	
13	Tariff Revenue	-	-	Carryforward from Sch G 4.4 L.11
14	Depreciation	-	-	Carryforward from Sch G 2.5 L.42
	Expense Credits			
15	Sundry	(4,698)	(3,197)	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.30
16	Greenhouse Gas Carbon Credits			
17	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch G 2.2 L.35
18	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.30
19	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.30
20	Pole Attachments	-	-	Prorated on Distribution Poles - Sch G 4.1 L.37
21	Secondary Energy	-	-	Production - Energy
22	Wheeling Revenues	-	-	Transmission - Demand
23	Application Fees	-	-	Accounting - Customer
24	Meter Test Revenues	-	-	Meters - Customer
25	Total Expense Credits	(4,698)	(3,197)	
26	Subtotal Expenses	1,431,632	974,404	
27	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch G 2.3 L.42
28	Subtotal Revenue Requirement Ex. Return	1,431,632	974,404	
29	Return on Debt	-	-	Prorated on Rate Base - Sch G 2.6 L.10
30	Return on Equity	-	-	Prorated on Rate Base - Sch G 2.6 L.12
31	Total Revenue Reqmt	1,431,632	974,404	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

Functional Classification of Plant in Service for the Allocation of O&M Expense

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution Substations Demand	Primary Lines Demand	Line Transformers Customer Demand	Customer	Secondary Lines Demand	Customer	Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Specifically Assigned Customer
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
	Production Hydraulic																
1	Bay D'Espoir	1,114,924,927	554,259,464	560,665,463	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	700,315	348,145	352,169	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	2,313,263	1,149,986	1,163,277	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	1,149,439	571,417	578,022	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	219,265	109,003	110,263	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	1,090,425	542,080	548,345	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Star Lake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other Hydraulic	282,500	140,438	142,062	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Subtotal Hydraulic	1,120,680,135	557,120,534	563,559,601	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Holyrood	437,045,123	388,270,887	48,774,236	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Turbines	200,469,524	200,469,524	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Diesel	12,942,773	12,942,773	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal Production	1,771,137,554	1,158,803,718	612,333,837	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
16	Lines	678,735,396	16,819,819	17,014,219	510,359,668	93,873,902	-	-	-	-	-	-	-	-	-	-	40,667,788
17	Terminal Stations	364,335,330	-	-	311,535,934	30,123,467	-	-	-	-	-	-	-	-	-	-	22,675,929
18	Term Stns - Hydraulic	55,383,108	27,532,447	27,850,661	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Holyrood	15,948,999	14,169,091	1,779,908	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Gas Tur/Dsl	453,488	453,488	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Term Stns - Distribution	19,394,860	-	-	-	-	19,394,860	-	-	-	-	-	-	-	-	-	-
22	Subtotal Term Stns	455,515,786	42,155,026	29,630,569	311,535,934	30,123,467	19,394,860	-	-	-	-	-	-	-	-	-	22,675,929
23	Subtotal Transmission	1,134,251,182	58,974,846	46,644,788	821,895,602	123,997,369	19,394,860	-	-	-	-	-	-	-	-	-	63,343,717
	Distribution																
24	Substations	44,549,497	-	-	-	-	44,549,497	-	-	-	-	-	-	-	-	-	-
25	Land & Land Improvements	3,384,051	-	-	-	-	-	2,551,406	325,038	-	295,935	211,672	-	-	-	-	-
26	Poles	160,253,236	-	-	-	-	-	92,682,138	31,674,373	-	16,404,803	19,491,922	-	-	-	-	-
27	Primary Conductor & Eqpt	25,812,930	-	-	-	-	-	22,896,069	2,916,861	-	-	-	-	-	-	-	-
28	Submarine Conductor	9,854,684	-	-	-	-	-	9,854,684	-	-	-	-	-	-	-	-	-
29	Transformers	29,563,425	-	-	-	-	-	-	10,672,397	18,891,029	-	-	-	-	-	-	-
30	Secondary Conductor&Eqpt	3,070,255	-	-	-	-	-	-	-	-	1,789,959	1,280,296	-	-	-	-	-
31	Services	6,162,249	-	-	-	-	-	-	-	-	-	-	6,162,249	-	-	-	-
32	Meters	9,766,093	-	-	-	-	-	-	-	-	-	-	-	9,766,093	-	-	-
33	Street Lighting	5,258,084	-	-	-	-	-	-	-	-	-	-	-	-	5,258,084	-	-
34	Subtotal Distribution	297,674,504	-	-	-	-	44,549,497	127,984,297	34,916,272	10,672,397	18,891,029	18,490,697	20,983,890	6,162,249	9,766,093	5,258,084	-
35	Subttl Prod, Trans, & Dist	3,203,063,241	1,217,778,563	658,978,625	821,895,602	123,997,369	63,944,357	127,984,297	34,916,272	10,672,397	18,891,029	18,490,697	20,983,890	6,162,249	9,766,093	5,258,084	63,343,717
36	General	233,673,560	109,613,189	38,726,936	47,661,908	6,622,265	4,454,820	8,401,746	2,292,138	700,608	1,240,134	1,213,853	1,377,523	404,531	1,239,177	345,176	1,835,657
37	NLSO	1,935,320	735,793	398,161	496,597	74,920	38,636	77,329	21,097	6,448	11,414	11,172	12,679	3,723	5,901	3,177	38,273
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Feasibility Studies	(180,127)	(180,127)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Software - General	13,917,263	5,291,230	2,863,253	3,571,124	538,767	277,837	556,090	151,711	46,371	82,081	80,342	91,175	26,775	42,434	22,846	275,228
42	Total Plant	3,452,409,258	1,333,238,649	700,966,975	873,625,231	131,233,322	68,715,650	137,019,463	37,381,217	11,425,824	20,224,658	19,796,065	22,465,267	6,597,278	11,053,604	5,629,283	65,492,875

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1	19
	Description	Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch G 4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch G 4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch G 4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch G 4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch G 4.1 L.1
6	Granite Canal	Production - Demand, Energy ratios Sch G 4.1 L.1
7	Exploits	Production - Demand, Energy ratios Sch G 4.1 L.1
8	Star Lake	Production - Demand, Energy ratios Sch G 4.1 L.1
9	Other Hydraulic	Production - Demand, Energy ratios Sch G 4.1 L.1, 2
10	Subtotal Hydraulic	
11	Holyrood	Production - Demand, Energy ratios Sch G 4.1 L.3
12	Gas Turbines	Production - Demand, Energy ratios Sch G 4.1 L.4
13	Roddickton	Production - Demand, Energy ratios Sch G 4.1 L.3
14	Diesel	Production - Demand, Energy ratios Sch G 4.1 L.5
15	Subtotal Production	
	Transmission	
16	Lines	Production - Demand, Energy ratios Sch G 4.1 L.17 Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
17	Terminal Stations	Production - Demand, Energy subtotals, L. 15; Transmission - Demand; Spec Assigned - Custmr
18	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch G 4.1 L.20
19	Term Stns - Holyrood	Production - Demand, Energy ratios Sch G 4.1 L.21
20	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch G 4.1 L.22, 23
21	Term Stns - Distribution	Distribution - Substations Demand
22	Subtotal Term Stns	
23	Subtotal Transmission	
	Distribution	
24	Substations	Production - Demand; Dist Substns - Demand
25	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.32
26	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.37
27	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.38
28	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.39
29	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch G 4.1 L.40
30	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.41
31	Services	Services Customer
32	Meters	Meters - Customer
33	Street Lighting	Street Lighting - Customer
34	Subtotal Distribution	
35	Subttl Prod, Trans, & Dist	
36	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch G 2.4 L.15, 16
37		
38	Telecontrol - Custmr & Spec	Specifically Assigned - Customer
39	Feasibility Studies	Production, Transmission - Demand
40	Feasibility Studies - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.35
41	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.35
42	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

		Functional Classification of Net Book Value																		
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18			
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution		Primary Lines		Line Transformers		Secondary Lines		Services		Meters	Street Lighting	Accounting	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
	Production Hydraulic																			
1	Bay D'Espoir	817,319,522	406,311,734	411,007,788	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	(308,183)	(153,206)	(154,977)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	2,850,569	1,417,096	1,433,474	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	(92,283)	(45,876)	(46,407)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	(34,788)	(17,294)	(17,494)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	(32,689)	(16,250)	(16,438)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Star Lake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other Small Hydraulic	264,354	131,418	132,937	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Subtotal Hydraulic	819,966,503	407,627,620	412,338,883	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Holyrood	146,045,381	129,746,716	16,298,665	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Turbines	126,292,246	126,292,246	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Diesel	5,172,218	5,172,218	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Subtotal Production Transmission	1,097,476,348	668,838,800	428,637,548	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Lines	417,821,974	9,064,399	9,169,164	351,254,883	34,898,171	-	-	-	-	-	-	-	-	-	-	-	-	-	13,435,358
17	Terminal Stations	251,981,802	-	-	221,893,580	16,264,106	-	-	-	-	-	-	-	-	-	-	-	-	-	13,824,115
18	Term Stns - Hydraulic	31,674,087	15,746,049	15,928,038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Holyrood	8,652,255	7,686,664	965,592	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Gas Tur/Dsl	354,105	354,105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Term Stns - Distribution	11,523,736	-	-	-	-	11,523,736	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal Term Stns	304,185,986	23,786,818	16,893,630	221,893,580	16,264,106	11,523,736	-	-	-	-	-	-	-	-	-	-	-	-	13,824,115
23	Subtotal Trans & Term Stns Distribution	722,007,960	32,851,217	26,062,793	573,148,463	51,162,277	11,523,736	-	-	-	-	-	-	-	-	-	-	-	-	27,259,474
24	Substations	51,022,061	-	-	-	-	51,022,061	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Land & Land Improvements	1,847,171	-	-	-	-	-	-	1,392,675	177,421	-	-	161,535	115,541	-	-	-	-	-	-
26	Poles	64,554,582	-	-	-	-	-	-	37,335,013	12,759,342	-	-	6,608,323	7,851,903	-	-	-	-	-	-
27	Primary Conductor & Eqpt	14,135,421	-	-	-	-	-	-	12,538,118	1,597,303	-	-	-	-	-	-	-	-	-	-
28	Submarine Conductor	1,560,642	-	-	-	-	-	-	1,560,642	-	-	-	-	-	-	-	-	-	-	-
29	Transformers	14,450,703	-	-	-	-	-	-	-	-	5,216,704	9,233,999	-	-	-	-	-	-	-	-
30	Secondary Conductor&Eqpt	899,951	-	-	-	-	-	-	-	-	-	524,671	375,280	-	-	-	-	-	-	-
31	Services	1,764,688	-	-	-	-	-	-	-	-	-	-	-	1,764,688	-	-	-	-	-	-
32	Meters	6,895,204	-	-	-	-	-	-	-	-	-	-	-	-	-	6,895,204	-	-	-	-
33	Street Lighting	2,172,511	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,172,511	-	-
34	Subtotal Distribution	159,302,933	-	-	-	-	51,022,061	52,826,448	14,534,065	5,216,704	9,233,999	7,294,530	8,342,723	1,764,688	6,895,204	2,172,511	-	-	-	-
35	Subttl Prod, Trans, & Dist	1,978,787,241	701,690,017	454,700,341	573,148,463	51,162,277	62,545,797	52,826,448	14,534,065	5,216,704	9,233,999	7,294,530	8,342,723	1,764,688	6,895,204	2,172,511	-	-	-	27,259,474
36	General	109,768,211	51,490,822	18,191,988	22,389,193	3,110,811	2,092,653	3,946,722	1,076,732	329,111	582,553	570,208	647,092	190,029	582,104	162,146	3,543,749	-	862,300	
37	NLSO	596,295	211,450	137,021	172,715	15,417	18,848	15,919	4,380	1,572	2,783	2,198	2,514	532	2,078	655	-	-	8,214	
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Feasibility Studies	(180,127)	(180,127)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Software - General	13,768,409	4,882,362	3,163,807	3,987,969	355,987	435,194	367,567	101,128	36,298	64,250	50,755	58,049	12,279	47,977	15,116	-	-	189,672	
42	Total Net Book Value	2,102,740,030	758,094,524	476,193,156	599,698,339	54,644,492	65,092,492	57,156,656	15,716,306	5,583,684	9,883,585	7,917,691	9,050,378	1,967,527	7,527,362	2,350,429	3,543,749	-	28,319,660	

		Functional Classification of Operating & Maintenance Expense																
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution		Line Transformers		Secondary Lines		Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Specifically Assigned Customer	
							Substations Demand	Primary Lines Demand	Demand	Customer	Demand	Customer						Demand
		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	
1	Hydraulic	15,587,945	7,749,191	7,838,754	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Holyrood / Thermal	20,137,025	17,889,733	2,247,292	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Gas Turbine	4,183,851	4,183,851	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Diesel	322,873	322,873	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Other	715,584	468,186	247,398	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Subtotal Production	40,947,279	30,613,834	10,333,445	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
8	Transmission Lines	2,078,729	54,796	55,430	1,662,675	305,827	-	-	-	-	-	-	-	-	-	-	-	
9	Terminal Stations	5,948,514	549,183	386,018	4,058,593	392,439	252,670	-	-	-	-	-	-	-	-	-	309,611	
10	Other	10,784,474	581,624	460,022	8,105,734	1,222,892	191,277	-	-	-	-	-	-	-	-	-	222,924	
11	Subtotal Transmission	18,811,716	1,185,603	901,470	13,827,003	1,921,158	443,947	-	-	-	-	-	-	-	-	-	532,535	
Distribution																		
12	Other	5,483,071	-	-	-	-	848,423	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	-	100,138	-	
13	Meters	359,493	-	-	-	-	-	-	-	-	-	-	-	359,493	-	-	-	
14	Subtotal Distribution	5,842,563	-	-	-	-	848,423	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	359,493	100,138	-	
15	Subttl Prod, Trans, & Dist	65,601,559	31,799,438	11,234,914	13,827,003	1,921,158	1,292,370	2,437,397	664,963	203,250	359,770	352,146	399,628	117,357	359,493	100,138	532,535	
16	Customer Accounting	2,188,530	-	-	-	-	-	-	-	-	-	-	-	-	-	2,188,530	-	
Administrative & General:																		
Plant-Related:																		
17	Production	7,256,926	4,747,995	2,508,931	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Prod - Gas Turb & Diesel	2,043,182	2,043,182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Transmission	5,495,558	302,640	239,366	4,217,708	636,315	99,528	-	-	-	-	-	-	-	-	-	-	
20	Distribution	2,747,806	-	-	-	-	411,232	1,181,411	322,309	98,516	174,381	170,686	193,700	56,883	90,150	48,537	-	
21	Prod, Trans, Distn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Prod, Trans, Distn and General	280,720	110,504	58,099	72,409	10,877	5,695	11,357	3,098	947	1,676	1,641	1,862	547	916	467	625	
23	Hydraulic & Holyrood	630,854	108,620	18,601	327,748	49,447	25,499	51,036	13,924	4,256	7,533	7,374	8,368	2,457	3,894	2,097	-	
24	Property Insurance	2,927,026	1,546,264	803,125	424,143	43,418	80,700	9,998	2,728	834	1,476	1,445	1,639	481	1,468	411	8,896	
Revenue-Related:																		
25	Municipal Tax	1,436,329	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
26	PUB Assessment	977,601	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
27	All Expense-Related	28,306,854	13,383,508	4,728,466	5,819,405	808,563	543,923	1,025,833	279,865	85,543	151,417	148,209	168,192	49,392	151,301	42,145	921,092	
28	Prod, Trans, and Distn Expense-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	Related	525,392	256,761	90,715	111,644	15,512	10,435	19,680	5,369	1,641	2,905	2,843	3,227	948	2,903	809	-	
30	Subtotal Admin & General	52,628,248	22,499,474	8,447,303	10,973,058	1,564,132	1,177,013	2,299,317	627,292	191,736	339,389	332,197	376,988	110,709	250,632	94,465	930,613	
Total Operating & Maintenance Expenses																		
		120,418,337	54,298,912	19,682,217	24,800,061	3,485,290	2,469,383	4,736,713	1,292,255	394,987	699,159	684,343	776,616	228,066	610,124	194,602	3,119,143	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

Functional Classification of Operating & Maintenance Expense (CONT'D.)

		19	20	21
Line No.	Description	Revenue Related		Basis of Functional Classification
		Municipal Tax	PUB Assessment	
	Production			
1	Hydraulic	-	-	Prorated on Hydraulic Plant in Service - Sch G 2.2 L.10
2	Holyrood / Thermal	-	-	Prorated on Holyrood Plant in Service - Sch G 2.2 L.11
3	Roddickton	-	-	Prorated on Roddickton Plant in Service - Sch G 2.2 L.13
4	Gas Turbine	-	-	Prorated on Gas Turbines Plant in Service - Sch G 2.2 L.12
5	Diesel	-	-	Prorated on Diesel Plant in Service - Sch G 2.2 L.14
6	Other	-	-	Prorated on Production Plant in Service - Sch G 2.2 L.15
7	Subtotal Production	-	-	
	Transmission			
8	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch G 2.2 L.16
9	Terminal Stations	-	-	Prorated on Terminal Stations Plant in Service - Sch G 2.2 L.22
10	Other	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.23
11	Subtotal Transmission	-	-	
	Distribution			
12	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch G 2.2 L. 34, less L. 32
13	Meters	-	-	Meters - Customer
14	Subtotal Distribution	-	-	
15	Subttl Prod, Trans, & Dist	-	-	
16	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
17	Production	-	-	Prorated on Production Plant in Service - Sch G 2.2 L.15
18	Prod - Gas Turb & Diesel	-	-	Prorated on Gas Turbine & Diesel Production Plant in Service - Sch G 2.2 L.12, 14
19	Transmission	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.23
20	Distribution	-	-	Prorated on Distribution Plant in Service - Sch G 2.2 L.34
21	Prod, Trans, Distn	-	-	Prorated on Prod, Trans & Distribution Plant in Service - Sch G 2.2 L.35
22	Prod, Trans, Distn and General	-	-	
22	Plant	-	-	Prorated on Total Plant in Service, Sch G 2.2, L. 42
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	-	-	Prorated on Total Plant in Service, Sch G 2.2, L. 35 Less L. 10 and L. 11
24	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch G 2.2 L.15, 22, 24, 36 - 38
	Revenue-Related:			
25	Municipal Tax	1,436,329	-	Revenue-related
26	PUB Assessment	-	977,601	Revenue-related
27	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 15, 16
	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L 15
28		-	-	
29	Subtotal Admin & General	1,436,329	977,601	
30	Total Operating & Maintenance Expenses	1,436,329	977,601	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

		Functional Classification of Depreciation Expense																	
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18		
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution	Primary Lines Demand (\$)	Customer (\$)	Line Transformers Demand (\$)	Secondary Lines Demand (\$)	Customer (\$)	Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)		
							Substations Demand (\$)												
	Production Hydraulic																		
1	Bay D'Esclair	18,997,665	9,444,255	9,553,410	-	-	-	-	-	-	-	-	-	-	-	-	-		
2	Upper Salmon	14,735	7,325	7,410	-	-	-	-	-	-	-	-	-	-	-	-	-		
3	Hinds Lake	30,668	15,246	15,422	-	-	-	-	-	-	-	-	-	-	-	-	-		
4	Cat Arm	5,515	2,741	2,773	-	-	-	-	-	-	-	-	-	-	-	-	-		
5	Paradise River	172	85	86	-	-	-	-	-	-	-	-	-	-	-	-	-		
6	Granite Canal	11,636	5,785	5,851	-	-	-	-	-	-	-	-	-	-	-	-	-		
7	Exploits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
8	Muskrat Falls Sustaining	720,638	358,249	362,389	-	-	-	-	-	-	-	-	-	-	-	-	-		
9	Other Small Hydraulic	3,222	1,602	1,620	-	-	-	-	-	-	-	-	-	-	-	-	-		
10	Subtotal Hydraulic	19,784,250	9,835,288	9,948,962	-	-	-	-	-	-	-	-	-	-	-	-	-		
11	Holyrood	31,706,547	28,168,096	3,538,451	-	-	-	-	-	-	-	-	-	-	-	-	-		
12	Gas Turbines	5,751,897	5,751,897	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
13	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
14	Diesel	200,824	200,824	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
15	Subtotal Production Transmission	57,443,518	43,956,105	13,487,413	-	-	-	-	-	-	-	-	-	-	-	-	-		
16	Lines	10,711,225	303,276	306,781	8,146,139	1,411,968	-	-	-	-	-	-	-	-	-	-	543,062		
17	Terminal Stations	7,749,078	-	-	6,810,065	568,684	-	-	-	-	-	-	-	-	-	-	370,329		
18	Term Stns - Hydraulic	930,929	462,790	468,139	-	-	-	-	-	-	-	-	-	-	-	-	-		
19	Term Stns - Holyrood	396,428	352,187	44,241	-	-	-	-	-	-	-	-	-	-	-	-	-		
20	Term Stns - Gas Tur/Dsl	9,923	9,923	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
21	Term Stns - Distribution	381,353	-	-	-	-	381,353	-	-	-	-	-	-	-	-	-	-		
22	Subtotal Term Stns	9,467,711	824,900	512,380	6,810,065	568,684	381,353	-	-	-	-	-	-	-	-	-	370,329		
23	Subtotal Transmission Distribution	20,178,936	1,128,176	819,161	14,956,204	1,980,652	381,353	-	-	-	-	-	-	-	-	-	913,390		
24	Substations	1,291,292	-	-	-	-	1,291,292	-	-	-	-	-	-	-	-	-	-		
25	Land & Land Improvements	43,713	-	-	-	-	-	32,958	4,199	-	-	3,823	2,734	-	-	-	-		
26	Poles	4,179,458	-	-	-	-	-	2,417,181	826,078	-	-	427,843	508,356	-	-	-	-		
27	Primary Conductor & Eqpt	547,959	-	-	-	-	-	486,039	61,919	-	-	-	-	-	-	-	-		
28	Submarine Conductor	178,060	-	-	-	-	-	178,060	-	-	-	-	-	-	-	-	-		
29	Transformers	761,905	-	-	-	-	-	-	-	275,048	486,857	-	-	-	-	-	-		
30	Secondary Conductor&Eqpt	42,305	-	-	-	-	-	-	-	-	24,664	17,641	-	-	-	-	-		
31	Services	116,962	-	-	-	-	-	-	-	-	-	-	116,962	-	-	-	-		
32	Meters	516,551	-	-	-	-	-	-	-	-	-	-	-	516,551	-	-	-		
33	Street Lighting	207,811	-	-	-	-	-	-	-	-	-	-	-	-	207,811	-	-		
34	Subtotal Distribution	7,886,016	-	-	-	-	1,291,292	3,114,238	892,196	275,048	486,857	456,329	528,731	116,962	516,551	207,811	-		
35	Subttl Prod, Trans, & Dist	85,508,470	45,084,281	14,306,574	14,956,204	1,980,652	1,672,645	3,114,238	892,196	275,048	486,857	456,329	528,731	116,962	516,551	207,811	913,390		
36	General	11,618,932	5,450,288	1,925,616	2,369,889	329,278	221,507	417,759	113,972	34,836	61,663	60,356	68,494	20,114	61,615	17,163	375,105		
37	NLSO	10,963	5,780	1,834	1,917	254	214	399	114	35	62	59	68	15	66	27	117		
38	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
39	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
40	GEC and AFUDC	383,174	202,028	64,110	67,021	8,876	7,495	13,955	3,998	1,233	2,182	2,045	2,369	524	2,315	931	4,093		
41	Software - General	2,990,596	1,576,789	500,362	523,082	69,272	58,500	108,918	31,204	9,620	17,027	15,960	18,492	4,091	18,066	7,268	31,945		
42	Total Depreciation Expense	100,512,135	52,319,167	16,798,496	17,918,114	2,388,332	1,960,361	3,655,270	1,041,484	320,771	567,792	534,749	618,155	141,706	598,613	233,200	1,040,820		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
1	Average Net Book Value	2,102,740,030	758,094,524	476,193,156	599,698,339	54,644,492	65,092,492	57,156,656	15,716,306	5,583,684	9,883,585	7,917,691	9,050,378	1,967,527	7,527,362	2,350,429	3,543,749	28,319,660
2	Cash Working Capital (Including Muskrat Falls)	116,490,187	41,997,856	26,380,736	33,222,829	3,027,263	3,606,074	3,166,435	870,671	309,332	547,543	438,634	501,384	108,999	417,010	130,212	196,321	1,568,887
3	Fuel Inventory - No. 6 Fuel	53,963,965	-	53,963,965	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	180,546	180,546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	7,763,006	7,763,006	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	39,481,123	15,246,674	8,016,131	9,990,619	1,500,760	785,820	1,566,930	427,485	130,664	231,286	226,384	256,909	75,445	126,407	64,375	86,271	748,965
7	Deferred Charges: Muskrat Falls	47,775	42,443	5,332	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Deferred Charges: Foreign Exchange Loss and																	
8	Regulatory Costs	101,068,768	36,438,018	22,888,353	28,824,663	2,626,502	3,128,688	2,747,250	755,408	268,381	475,057	380,566	435,009	94,570	361,805	112,974	170,331	1,361,192
9	Retired Asset Pool	28,866,724	10,407,233	6,537,250	8,232,747	750,168	893,599	784,655	215,756	76,654	135,683	108,695	124,245	27,010	103,337	32,267	48,649	388,776
10	Total Rate Base	2,450,602,123	870,170,300	593,984,922	679,969,197	62,549,186	73,506,673	65,421,926	17,985,626	6,368,715	11,273,154	9,071,971	10,367,924	2,273,552	8,535,921	2,690,257	4,045,320	32,387,481
11	Less: Rural Asset Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate Base Available for Equity Return	2,450,602,123	870,170,300	593,984,922	679,969,197	62,549,186	73,506,673	65,421,926	17,985,626	6,368,715	11,273,154	9,071,971	10,367,924	2,273,552	8,535,921	2,690,257	4,045,320	32,387,481
13	Return on Debt	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863
14	Return on Equity	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646
15	Return on Rate Base	119,589,384	42,464,311	28,986,464	33,182,497	3,052,400	3,587,126	3,192,590	877,699	310,793	550,130	442,712	505,955	110,949	416,553	131,285	197,412	1,580,509

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	19 Basis of Functional Classification
1	Average Net Book Value	Sch G 2.3 , L. 42
2	Cash Working Capital (Including Muskrat F: Prorated on Average Net Book Value, L. 1	
3	Fuel Inventory - No. 6 Fuel	Production - Demand, Energy ratios Sch G 4.1 L.10
4	Fuel Inventory - Diesel	Production - Demand, Energy ratios Sch G 4.1 L.12
5	Fuel Inventory - Gas Turbine	Production - Demand, Energy ratios Sch G 4.1 L.11
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch G 2.2, L. 42
7	Deferred Charges: Muskrat Falls Deferred Charges: Foreign Exchange Loss and	Production - Demand, Energy ratios Sch G 4.1 L.3
8	Regulatory Costs	Prorated on Average Net Book Value, L. 1
9	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
10	Total Rate Base	
11	Less: Rural Asset Portion	N/A
12	Rate Base Available for Equity Return	
13	Return on Debt	L.10 x Sch G 1.1,p2,L.16
14	Return on Equity	L.12 x Sch G 1.1,p2,L.19
15	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Basis of Allocation to Classes of Service

1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand (1 CP kW)	Production Energy (MWh @ Gen)	Transmission Demand (CP kW)	Rural Prod & Transmission Demand (CP kW)	Distribution	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting Customer	Specifically Assigned Customer
							Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
							(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	Mtd Rural Cust)	(Rural Cust)			
Amounts																		
1	Newfoundland Power	-	1,459,198	6,292,250	1,435,869	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	81,911	641,688	78,487	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																		
4	1.1 Domestic	-	33,033	123,930	31,652	31,652	29,317	29,317	11,494	25,936	11,494	25,936	11,494	11,494	11,494	-	11,494	-
5	1.12 Domestic All Electric	-	38,341	167,083	36,739	36,739	34,028	34,028	8,714	30,104	8,714	30,104	8,714	8,714	8,714	-	8,714	-
6	1.3 Special	-	133	393	127	127	118	118	1	104	1	104	1	1	1	-	1	-
7	2.1 GS 0-10 kW	-	15,207	82,954	14,571	14,571	13,496	13,496	3,042	11,940	3,042	11,940	3,042	14,508	14,508	-	3,042	-
8	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.3 GS 110-1,000 kVa	-	10,056	61,765	9,636	9,636	8,925	8,925	84	7,321	84	7,321	84	703	703	-	84	-
10	2.4 GS Over 1,000 kVa	-	5,870	44,445	5,625	5,625	5,210	5,210	8	1,902	8	1,902	8	67	67	-	8	-
11	4.1 Street and Area Lighting	-	629	2,365	603	603	558	558	1,057	494	1,057	494	1,057	-	-	1	1,057	-
12	Subtotal Rural	-	103,269	482,936	98,953	98,953	91,651	91,651	24,398	77,803	24,398	77,803	24,398	35,487	35,487	1	24,398	-
13	Total	-	1,644,378	7,416,874	1,613,309	98,953	91,651	91,651	24,398	77,803	24,398	77,803	24,398	35,487	35,487	1	24,398	-
Ratios Excluding Return on Equity																		
14	Newfoundland Power	-	0.8874	0.8484	0.8900	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.0498	0.0865	0.0486	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																		
17	1.1 Domestic	-	0.0201	0.0167	0.0196	0.3199	0.3199	0.3199	0.4711	0.3334	0.4711	0.3334	0.4711	0.3239	0.3239	-	0.4711	-
18	1.12 Domestic All Electric	-	0.0233	0.0225	0.0228	0.3713	0.3713	0.3713	0.3571	0.3869	0.3571	0.3869	0.3571	0.2455	0.2455	-	0.3571	-
19	1.3 Special	-	0.0001	0.0001	0.0001	0.0013	0.0013	0.0013	0.0000	0.0013	0.0000	0.0013	0.0000	0.0000	0.0000	-	0.0000	-
20	2.1 GS 0-10 kW	-	0.0092	0.0112	0.0090	0.1473	0.1473	0.1473	0.1247	0.1535	0.1247	0.1535	0.1247	0.4088	0.4088	-	0.1247	-
21	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	2.3 GS 110-1,000 kVa	-	0.0061	0.0083	0.0060	0.0974	0.0974	0.0974	0.0034	0.0941	0.0034	0.0941	0.0034	0.0198	0.0198	-	0.0034	-
23	2.4 GS Over 1,000 kVa	-	0.0036	0.0060	0.0035	0.0568	0.0568	0.0568	0.0003	0.0245	0.0003	0.0245	0.0003	0.0019	0.0019	-	0.0003	-
24	4.1 Street and Area Lighting	-	0.0004	0.0003	0.0004	0.0061	0.0061	0.0061	0.0433	0.0063	0.0433	0.0063	0.0433	-	-	1.0000	0.0433	-
25	Subtotal Rural	-	0.0628	0.0651	0.0613	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
26	Total	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related		20
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)	
	Amounts			
1	Newfoundland Power	-	484,507,755	
2	Industrial - Firm	-	43,914,366	
3	Industrial - Non-Firm	-	-	
	Rural			
4	1.1 Domestic	13,704,053	13,704,053	
5	1.12 Domestic All Electric	17,350,913	17,350,913	
6	1.3 Special	19,223	19,223	
7	2.1 GS 0-10 kW	9,465,475	9,465,475	
8	2.2 GS 10-100 kW	-	-	
9	2.3 GS 110-1,000 kVa	6,141,548	6,141,548	
10	2.4 GS Over 1,000 kVa	3,400,344	3,400,344	
11	4.1 Street and Area Lighting	993,685	993,685	
12	Subtotal Rural	51,075,241	51,075,241	
13	Total	51,075,241	579,497,362	
	Ratios Excluding Return on Equity			
14	Newfoundland Power	-	0.8361	
15	Industrial - Firm	-	0.0758	
16	Industrial - Non-Firm	-	-	
	Rural			
17	1.1 Domestic	0.2683	0.0236	
18	1.12 Domestic All Electric	0.3397	0.0299	
19	1.3 Special	0.0004	0.0000	
20	2.1 GS 0-10 kW	0.1853	0.0163	
21	2.2 GS 10-100 kW	-	-	
22	2.3 GS 110-1,000 kVa	0.1202	0.0106	
23	2.4 GS Over 1,000 kVa	0.0666	0.0059	
24	4.1 Street and Area Lighting	0.0195	0.0017	
25	Subtotal Rural	1.0000	0.0881	
26	Total	1.0000	1.0000	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution		Customer (\$)	Line Transformers Demand (\$)	Secondary Lines Demand (\$)	Customer (\$)	Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)	
							Substations Demand (\$)	Primary Lines Demand (\$)										
	Allocated Rev Reqmt Excl Return																	
1	Newfoundland Power	916,403,239	459,807,370	416,510,027	37,946,237	-	-	-	-	-	-	-	-	-	-	-	-	1,324,923
2	Industrial - Firm	70,681,419	25,810,809	42,475,988	2,074,210	-	-	-	-	-	-	-	-	-	-	-	-	246,571
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	30,829,070	10,408,985	8,203,458	836,488	2,182,159	1,414,326	2,457,945	985,978	238,168	595,767	364,803	587,292	119,519	390,844	-	1,636,173	-
5	1.12 Domestic All Electric	35,627,036	12,081,744	11,059,927	970,914	2,532,839	1,641,613	2,852,945	747,476	276,443	451,655	423,428	445,230	90,608	296,301	-	1,240,394	-
6	1.3 Special	98,968	41,869	26,009	3,365	8,777	5,689	9,887	86	958	52	1,467	51	10	34	-	142	-
7	2.1 GS 0-10 kW	15,665,063	4,791,786	5,491,084	385,078	1,004,559	651,086	1,131,517	260,908	109,641	157,651	167,937	155,408	150,865	493,348	-	432,962	-
8	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.3 GS 110-1,000 kVa	9,766,540	3,168,744	4,088,493	254,647	664,301	430,555	748,257	7,163	67,231	4,328	102,978	4,267	7,310	23,906	-	11,886	-
10	2.4 GS Over 1,000 kVa	6,167,251	1,849,783	2,941,987	148,652	387,792	251,340	436,802	686	17,469	415	26,757	409	700	2,290	-	1,139	-
11	4.1 Street and Area Lighting	1,304,005	198,256	156,568	15,932	41,563	26,938	46,815	90,629	4,536	54,762	6,948	53,983	-	-	427,156	150,394	-
12	Subtotal Rural	99,457,933	32,541,166	31,967,527	2,615,076	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	-
13	Total	1,086,542,591	518,159,345	490,953,541	42,635,523	6,821,991	4,421,548	7,684,168	2,092,926	714,446	1,264,629	1,094,319	1,246,640	369,014	1,206,724	427,156	3,473,090	1,571,495
	Allocated Return on Debt																	
14	Newfoundland Power	57,498,958	23,242,527	15,167,953	18,215,993	-	-	-	-	-	-	-	-	-	-	-	-	872,485
15	Industrial - Firm	3,949,632	1,304,695	1,546,839	995,719	-	-	-	-	-	-	-	-	-	-	-	-	102,379
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	4,045,899	526,158	298,743	401,554	602,231	707,732	629,891	255,038	63,905	159,855	91,030	147,018	22,165	83,217	-	57,363	-
18	1.12 Domestic All Electric	4,460,358	610,713	402,767	466,085	699,012	821,466	731,116	193,346	74,174	121,187	105,658	111,456	16,803	63,087	-	43,487	-
19	1.3 Special	13,168	2,116	947	1,615	2,422	2,847	2,534	22	257	14	366	13	2	7	-	5	-
20	2.1 GS 0-10 kW	1,888,269	242,217	199,968	184,856	277,238	325,805	289,971	67,488	29,419	42,301	41,906	38,904	27,978	105,042	-	15,179	-
21	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	2.3 GS 110-1,000 kVa	1,076,525	160,175	148,890	122,243	183,334	215,450	191,754	1,853	18,039	1,161	25,696	1,068	1,356	5,090	-	417	-
23	2.4 GS Over 1,000 kVa	629,146	93,504	107,138	71,360	107,023	125,771	111,938	178	4,687	111	6,677	102	130	488	-	40	-
24	4.1 Street and Area Lighting	201,169	10,022	5,702	7,648	11,470	13,480	11,997	23,443	1,217	14,694	1,734	13,514	-	-	80,977	5,273	-
25	Subtotal Rural	12,314,534	1,644,904	1,164,154	1,255,360	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	-
26	Total	73,763,124	26,192,126	17,878,946	20,467,073	1,882,730	2,212,551	1,969,200	541,367	191,698	339,322	273,066	312,075	68,434	256,931	80,977	121,764	974,863
	Allocated Return on Equity																	
27	Newfoundland Power	35,721,944	14,439,709	9,423,280	11,316,913	-	-	-	-	-	-	-	-	-	-	-	-	542,042
28	Industrial - Firm	2,453,758	810,558	960,993	618,603	-	-	-	-	-	-	-	-	-	-	-	-	63,604
29	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
30	1.1 Domestic	2,513,565	326,882	185,598	249,470	374,144	439,687	391,327	158,446	39,702	99,312	56,553	91,337	13,770	51,700	-	35,638	-
31	1.12 Domestic All Electric	2,771,053	379,413	250,224	289,561	434,270	510,346	454,215	120,119	46,082	75,289	65,642	69,243	10,439	39,194	-	27,017	-
32	1.3 Special	8,181	1,315	588	1,003	1,505	1,769	1,574	14	160	9	227	8	1	4	-	3	-
33	2.1 GS 0-10 kW	1,173,111	150,480	124,232	114,844	172,237	202,410	180,148	41,928	18,277	26,280	26,034	24,169	17,382	65,259	-	9,430	-
34	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	2.3 GS 110-1,000 kVa	668,805	99,511	92,500	75,945	113,898	133,851	119,129	1,151	11,207	721	15,964	664	842	3,162	-	259	-
36	2.4 GS Over 1,000 kVa	390,865	58,090	66,561	44,333	66,489	78,137	69,543	110	2,912	69	4,148	64	81	303	-	25	-
37	4.1 Street and Area Lighting	124,979	6,226	3,542	4,752	7,126	8,375	7,453	14,564	756	9,129	1,077	8,396	-	-	50,308	3,276	-
38	Subtotal Rural	7,650,558	1,021,917	723,245	779,908	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	-
39	Total	45,826,260	16,272,185	11,107,518	12,715,424	1,169,670	1,374,575	1,223,390	336,331	119,095	210,808	169,646	193,880	42,515	159,622	50,308	75,647	605,646

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONTD.)

Line No.	Description	19	20
		Revenue Related	
		Municipal Tax	PUB Assessment
			(\$)
1	Allocated Rev Reqmt Excl Return		
	Newfoundland Power	-	814,682
2	Industrial - Firm	-	73,840
3	Industrial - Non-Firm	-	-
	Rural		
4	1.1 Domestic	384,123	23,043
5	1.12 Domestic All Electric	486,344	29,175
6	1.3 Special	539	32
7	2.1 GS 0-10 kW	265,316	15,916
8	2.2 GS 10-100 kW	-	-
9	2.3 GS 110-1,000 kVa	172,147	10,327
10	2.4 GS Over 1,000 kVa	95,311	5,718
11	4.1 Street and Area Lighting	27,853	1,671
12	Subtotal Rural	1,431,632	85,881
13	Total	1,431,632	974,404
	Allocated Return on Debt		
14	Newfoundland Power	-	-
15	Industrial - Firm	-	-
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	-	-
18	1.12 Domestic All Electric	-	-
19	1.3 Special	-	-
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	-	-
22	2.3 GS 110-1,000 kVa	-	-
23	2.4 GS Over 1,000 kVa	-	-
24	4.1 Street and Area Lighting	-	-
25	Subtotal Rural	-	-
26	Total	-	-
	Allocated Return on Equity		
27	Newfoundland Power	-	-
28	Industrial - Firm	-	-
29	Industrial - Non-Firm	-	-
	Rural		
30	1.1 Domestic	-	-
31	1.12 Domestic All Electric	-	-
32	1.3 Special	-	-
33	2.1 GS 0-10 kW	-	-
34	2.2 GS 10-100 kW	-	-
35	2.3 GS 110-1,000 kVa	-	-
36	2.4 GS Over 1,000 kVa	-	-
37	4.1 Street and Area Lighting	-	-
38	Subtotal Rural	-	-
39	Total	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Rural Prod & Transmission Demand (\$)	Distribution		Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Services (\$)	Meters (\$)	Street Lighting (\$)	Accounting (\$)	Specifically Assigned Customer (\$)
							Substations Demand (\$)	Primary Lines Demand (\$)										
40	Newfoundland Power	1,009,624,141	497,489,607	441,101,260	67,479,142	-	-	-	-	-	-	-	-	-	-	-	-	2,739,450
41	Industrial - Firm	77,084,808	27,926,062	44,983,819	3,688,533	-	-	-	-	-	-	-	-	-	-	-	-	412,554
42	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	37,388,534	11,262,025	8,687,799	1,487,512	3,158,534	2,561,745	3,479,163	1,399,461	341,774	854,933	512,386	825,647	155,455	525,761	-	1,729,173	-
44	1.12 Domestic All Electric	42,858,448	13,071,870	11,712,918	1,726,560	3,666,121	2,973,426	4,038,276	1,060,941	396,699	648,130	594,728	625,929	117,851	398,583	-	1,310,898	-
45	1.3 Special	120,316	45,300	27,545	5,983	12,705	10,304	13,994	122	1,375	74	2,061	72	14	46	-	150	-
46	2.1 GS 0-10 kW	18,726,443	5,184,483	5,815,284	684,777	1,454,034	1,179,302	1,601,636	370,324	157,336	226,231	235,877	218,482	196,225	663,649	-	457,572	-
47	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	2.3 GS 110-1,000 kVa	11,511,869	3,428,429	4,329,882	452,834	961,533	779,856	1,059,140	10,167	96,478	6,211	144,639	5,998	9,508	32,158	-	12,562	-
49	2.4 GS Over 1,000 kVa	7,187,262	2,001,377	3,115,685	264,346	561,304	455,248	618,283	974	25,068	595	37,582	575	911	3,081	-	1,204	-
50	4.1 Street and Area Lighting	1,630,154	214,503	165,812	28,332	60,159	48,792	66,266	128,636	6,510	78,584	9,759	75,892	-	-	558,441	158,943	-
51	Subtotal Rural	119,423,025	35,207,987	33,854,926	4,650,345	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	-
52	Total	1,206,131,974	560,623,656	519,940,005	75,818,020	9,874,391	8,008,674	10,876,758	2,970,625	1,025,239	1,814,759	1,537,032	1,752,595	479,963	1,623,277	558,441	3,670,502	3,152,004
	Re-classification of Revenue-Related																	
53	Newfoundland Power	-	401,757	356,219	54,494	-	-	-	-	-	-	-	-	-	-	-	-	2,212
54	Industrial - Firm	-	26,776	43,132	3,537	-	-	-	-	-	-	-	-	-	-	-	-	396
55	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
56	1.1 Domestic	0	123,995	95,653	16,378	34,776	28,205	38,306	15,408	3,763	9,413	5,641	9,090	1,712	5,789	-	19,038	-
57	1.12 Domestic All Electric	0	159,148	142,603	21,021	44,634	36,201	49,165	12,917	4,830	7,891	7,241	7,621	1,435	4,853	-	15,960	-
58	1.3 Special	0	216	131	29	61	49	67	1	7	0	10	0	0	0	-	1	-
59	2.1 GS 0-10 kW	(0)	79,047	88,665	10,441	22,169	17,981	24,420	5,646	2,399	3,449	3,596	3,331	2,992	10,119	-	6,977	-
60	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	2.3 GS 110-1,000 kVa	(0)	55,219	69,738	7,293	15,487	12,561	17,059	164	1,554	100	2,330	97	153	518	-	202	-
62	2.4 GS Over 1,000 kVa	(0)	28,534	44,420	3,769	8,003	6,490	8,815	14	357	8	536	8	13	44	-	17	-
63	4.1 Street and Area Lighting	-	3,957	3,058	523	1,110	900	1,222	2,373	120	1,449	180	1,400	-	-	10,300	2,932	-
64	Subtotal Rural	0	450,115	444,269	59,452	126,239	102,387	139,054	36,522	13,029	22,311	19,534	21,547	6,304	21,322	10,300	45,127	-
65	Total	0	878,648	843,620	117,483	126,239	102,387	139,054	36,522	13,029	22,311	19,534	21,547	6,304	21,322	10,300	45,127	2,608
	Total Allocated Revenue Requirement																	
66	Newfoundland Power	1,009,624,141	497,891,363	441,457,479	67,533,636	-	-	-	-	-	-	-	-	-	-	-	-	2,741,662
67	Industrial - Firm	77,084,808	27,952,838	45,026,951	3,692,069	-	-	-	-	-	-	-	-	-	-	-	-	412,949
68	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
69	1.1 Domestic	37,388,534	11,386,020	8,783,452	1,503,889	3,193,310	2,589,950	3,517,468	1,414,869	345,537	864,346	518,027	834,738	157,166	531,549	-	1,748,212	-
70	1.12 Domestic All Electric	42,858,448	13,231,018	11,855,521	1,747,581	3,710,756	3,009,627	4,087,441	1,073,858	401,528	656,021	601,969	633,549	119,286	403,435	-	1,326,858	-
71	1.3 Special	120,316	45,516	27,676	6,012	12,765	10,353	14,061	122	1,381	75	2,071	72	14	46	-	151	-
72	2.1 GS 0-10 kW	18,726,443	5,263,530	5,903,949	695,218	1,476,204	1,197,282	1,626,056	375,970	159,735	229,681	239,474	221,813	199,217	673,767	-	464,548	-
73	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	2.3 GS 110-1,000 kVa	11,511,869	3,483,648	4,399,620	460,128	977,020	792,417	1,076,199	10,330	98,032	6,311	146,968	6,095	9,661	32,676	-	12,764	-
75	2.4 GS Over 1,000 kVa	7,187,262	2,029,911	3,160,106	268,115	569,306	461,739	627,098	988	25,425	604	38,118	583	924	3,125	-	1,221	-
76	4.1 Street and Area Lighting	1,630,154	218,460	168,871	28,855	61,269	49,692	67,488	131,009	6,630	80,033	9,939	77,292	-	-	568,741	161,874	-
77	Subtotal Rural	119,423,025	35,658,103	34,299,195	4,709,797	10,000,630	8,111,060	11,015,811	3,007,147	1,038,269	1,837,070	1,556,565	1,774,142	486,268	1,644,599	568,741	3,715,628	-
78	Total	1,206,131,974	561,502,304	520,783,625	75,935,503	10,000,630	8,111,060	11,015,811	3,007,147	1,038,269	1,837,070	1,556,565	1,774,142	486,268	1,644,599	568,741	3,715,628	3,154,612

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONTD.)

		19	20	
		Revenue Related		
Line No.	Description	Municipal Tax (\$)	PUB Assessment (\$)	Basis of Proration
	Total Revenue Requirement			
40	Newfoundland Power	-	814,682	
41	Industrial - Firm	-	73,840	
42	Industrial - Non-Firm	-	-	
	Rural			
43	1.1 Domestic	384,123	23,043	
44	1.12 Domestic All Electric	486,344	29,175	
45	1.3 Special	539	32	
46	2.1 GS 0-10 kW	265,316	15,916	
47	2.2 GS 10-100 kW	-	-	
48	2.3 GS 110-1,000 kVa	172,147	10,327	
49	2.4 GS Over 1,000 kVa	95,311	5,718	
50	4.1 Street and Area Lighting	27,853	1,671	
51	Subtotal Rural	1,431,632	85,881	
52	Total	1,431,632	974,404	
	Re-classification of Revenue-Related			
53	Newfoundland Power	-	(814,682)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
54	Industrial - Firm	-	(73,840)	
55	Industrial - Non-Firm	-	-	
	Rural			
56	1.1 Domestic	(384,123)	(23,043)	
57	1.12 Domestic All Electric	(486,344)	(29,175)	
58	1.3 Special	(539)	(32)	
59	2.1 GS 0-10 kW	(265,316)	(15,916)	
60	2.2 GS 10-100 kW	-	-	
61	2.3 GS 110-1,000 kVa	(172,147)	(10,327)	
62	2.4 GS Over 1,000 kVa	(95,311)	(5,718)	
63	4.1 Street and Area Lighting	(27,853)	(1,671)	
64	Subtotal Rural	(1,431,632)	(85,881)	
65	Total	(1,431,632)	(974,404)	
	Total Allocated Revenue Requirement			
66	Newfoundland Power	-	-	
67	Industrial - Firm	-	-	
68	Industrial - Non-Firm	-	-	
	Rural			
69	1.1 Domestic	-	-	
70	1.12 Domestic All Electric	-	-	
71	1.3 Special	-	-	
72	2.1 GS 0-10 kW	-	-	
73	2.2 GS 10-100 kW	-	-	
74	2.3 GS 110-1,000 kVa	-	-	
75	2.4 GS Over 1,000 kVa	-	-	
76	4.1 Street and Area Lighting	-	-	
77	Subtotal Rural	-	-	
78	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Interconnected
Allocation of Specifically Assigned Amounts to Classes of Service

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	
Line No.	Description	Total Amount (\$)	OM&A				Depreciation				Expense Credits		Subtotal Excluding Return (\$)	Return on Debt (\$) (NBV)	Return on Equity (\$) (NBV)	Subtotal Excl Rev Related (\$)	Revenue Related (\$)	
			Transmission Lines (\$) (Plant)	Administrative & Terminals (\$) (Plant)	General (\$) (C3 & C4)	Other (\$) (C3 & C4)	Transmission Lines (\$) (Direct)	Terminals (\$) (Direct)	Telecontrol & Feasibility Study (\$) (Direct)	General (\$) (Exp C3,4,6)	Rental Income (\$) (Plant)	Other (\$) (C6)						
Basis of Allocation - Amounts																		
1	Newfoundland Power Industrial		28,117,625	14,054,941	42,172,565	42,172,565	-	-	-	391,617	42,172,565	42,172,565	24,396,729	-	24,396,729	24,396,729	-	-
2	Vale		668,081	3,422,177	4,090,259	4,090,259	-	-	-	86,509	4,090,259	4,090,259	2,197,177	-	2,197,177	2,197,177	-	-
3	Corner Brook P& P - CB		-	16,570	16,570	16,570	-	-	-	3,679	16,570	16,570	(4,394)	-	(4,394)	(4,394)	-	-
4	Corner Brook P& P - DL		-	56,030	56,030	56,030	-	-	-	-	56,030	56,030	11,326	-	11,326	11,326	-	-
5	North Atlantic Refining Limited		-	1,820,569	1,820,569	1,820,569	-	-	-	34,958	1,820,569	1,820,569	658,707	-	658,707	658,707	-	-
6	Teck Resources		4,534,363	947,903	5,482,265	5,482,265	-	-	-	8,049	5,482,265	5,482,265	(72)	-	(72)	(72)	-	-
7	Marathon Gold		7,347,720	2,357,740	9,705,459	9,705,459	-	-	-	7,723	9,705,459	9,705,459	0	-	0	0	-	-
8	Subtotal Industrial		12,550,164	8,620,989	21,171,152	21,171,152	-	-	-	140,918	21,171,152	21,171,152	2,862,745	-	2,862,745	2,862,745	-	-
9	Total		40,667,788	22,675,929	63,343,717	63,343,717	-	-	-	532,535	63,343,717	63,343,717	27,259,474	-	27,259,474	27,259,474	-	-
Basis of Allocation - Ratios																		
11	Newfoundland Power Industrial		0.6914	0.6198	0.6658	0.6658	-	-	-	0.7354	0.6658	0.6658	0.8950	-	0.8950	0.8950	-	-
12	Vale		0.0164	0.1509	0.0646	0.0646	-	-	-	0.1624	0.0646	0.0646	0.0806	-	0.0806	0.0806	-	-
13	Corner Brook P& P - CB		-	0.0007	0.0003	0.0003	-	-	-	0.0069	0.0003	0.0003	(0.0002)	-	(0.0002)	(0.0002)	-	-
14	Corner Brook P& P - DL		-	0.0025	0.0009	0.0009	-	-	-	-	0.0009	0.0009	0.0004	-	0.0004	0.0004	-	-
15	North Atlantic Refining Ltd.		-	0.0803	0.0287	0.0287	-	-	-	0.0656	0.0287	0.0287	0.0242	-	0.0242	0.0242	-	-
16	Teck Resources		0.1115	0.0418	0.0865	0.0865	-	-	-	0.0151	0.0865	0.0865	(0.0000)	-	(0.0000)	(0.0000)	-	-
17	Marathon Gold		0.1807	0.1040	0.1532	0.1532	-	-	-	0.0145	0.1532	0.1532	0.0000	-	0.0000	0.0000	-	-
18	Subtotal Industrial		0.3086	0.3802	0.3342	0.3342	-	-	-	0.2646	0.3342	0.3342	0.1050	-	0.1050	0.1050	-	-
19	Total		1.0000	1.0000	1.0000	1.0000	-	-	-	1.0000	1.0000	1.0000	1.0000	-	1.0000	1.0000	-	-
Amounts Allocated																		
20	Newfoundland Power Industrial	2,741,662	-	227,683	-	163,934	536,015	304,821	-	93,709	(79)	(1,160)	-	1,324,923	872,485	542,042	2,739,450	2,212
21	Vale	284,823	-	50,296	-	36,214	7,047	43,021	-	20,701	(8)	(112)	-	157,157	78,576	48,816	284,550	273
22	Corner Brook P& P - CB	4,556	-	2,139	-	1,540	-	247	-	880	(0)	(0)	-	4,807	(157)	(98)	4,552	4
23	Corner Brook P& P - DL	1,261	-	-	-	-	-	605	-	-	(0)	(2)	-	603	405	252	1,260	1
24	North Atlantic Refining Ltd.	103,072	-	20,324	-	14,634	-	21,512	-	8,365	(3)	(50)	-	64,782	23,557	14,635	102,974	99
25	Teck Resources	9,942	-	4,679	-	3,369	-	123	-	1,926	(10)	(151)	-	9,937	(3)	(2)	9,933	10
26	Marathon Gold	9,295	-	4,490	-	3,233	(0)	-	-	1,848	(18)	(267)	-	9,286	0	0	9,286	9
27	Subtotal Industrial	412,949	-	81,929	-	58,990	7,047	65,508	-	33,720	(40)	(582)	-	246,571	102,379	63,604	412,554	396
28	Total	3,154,612	-	309,611	-	222,924	543,062	370,329	-	127,430	(119)	(1,742)	-	1,571,495	974,863	605,646	3,152,004	2,608

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Expenses																
1	Operating & Maintenance	12,671,431	1,006,216	50,059	4,679,099	784,698	1,450,041	416,403	326,508	577,947	229,782	256,167	87,963	286,694	96,441	1,787,728	30,171
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	159,728	159,728	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	1,554,061	515,843	1,038,217	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	6,405,729	416,890	-	2,348,631	779,584	1,022,044	304,623	219,390	388,338	161,496	184,765	44,474	272,690	91,199	164,902	6,704
	Expense Credits																
8	Sundry	(41,444)	(3,291)	(164)	(15,304)	(2,566)	(4,743)	(1,362)	(1,068)	(1,890)	(752)	(838)	(288)	(938)	(315)	(5,847)	(99)
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(249,068)	-	-	-	-	(144,048)	(49,229)	-	-	(25,497)	(30,295)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(7,848)	-	-	-	-	-	-	-	-	-	-	-	-	-	(7,848)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(298,359)	(3,291)	(164)	(15,304)	(2,566)	(148,790)	(50,591)	(1,068)	(1,890)	(26,248)	(31,132)	(288)	(938)	(315)	(13,695)	(99)
18	Subtotal Expenses	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776
21	Return on Debt	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921
22	Return on Equity	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057
23	Total Revenue Requirement	29,211,220	2,762,341	1,088,113	11,524,019	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	44,754

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	Description	Revenue Related		Basis of Functional Classification
		18	19	
		Municipal Tax	PUB Assessment	
	Expenses			
1	Operating & Maintenance	571,245	34,268	Carryforward from Sch G 2.4 L.24
2	Fuels	-	-	
3	Fuels-Diesel	-	-	Production - Demand
4	Fuels-Gas Turbine	-	-	Production - Demand
5	Power Purchases -CF(L)Co	-	-	Carryforward from Sch G 4.4 L.17
6	Power Purchases-Other	-	-	Carryforward from Sch G 4.4 L.18
7	Depreciation	-	-	Carryforward from Sch G 2.5 L.24
	Expense Credits			
8	Sundry	(1,868)	(112)	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch G 2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch G 4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch G 4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	Total Expense Credits	(1,868)	(112)	
18	Subtotal Expenses	569,376	34,156	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch G 2.3 L.24
20	Subtotal Revenue Requirement Ex. Return	569,376	34,156	
21	Return on Debt	-	-	Prorated on Rate Base - Sch G 2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch G 2.6 L.11
23	Total Revenue Requirement	569,376	34,156	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Production																		
1	Gas Turbines	28,768,434	28,768,434	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Diesel	3,370,355	3,370,355	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Subtotal Production	32,138,789	32,138,789	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
4	Lines	4,560,341	-	-	4,560,341	-	-	-	-	-	-	-	-	-	-	-	-	
5	Terminal Stations	94,319,120	-	-	71,206,182	20,082,084	-	-	-	-	-	-	-	-	-	-	3,030,854	
6	Subtotal Transmission	98,879,461	-	-	75,766,523	20,082,084	-	-	-	-	-	-	-	-	-	-	3,030,854	
Distribution																		
7	Substations	12,569,787	-	-	-	12,569,787	-	-	-	-	-	-	-	-	-	-	-	
8	Land & Land Improvements	1,261,995	-	-	-	-	951,481	121,215	-	-	110,362	78,938	-	-	-	-	-	
9	Poles	43,568,475	-	-	-	-	25,197,741	8,611,396	-	-	4,460,018	5,299,321	-	-	-	-	-	
10	Primary Conductor & Eqpt	7,376,348	-	-	-	-	6,542,820	833,527	-	-	-	-	-	-	-	-	-	
11	Submarine Conductor	620,108	-	-	-	-	620,108	-	-	-	-	-	-	-	-	-	-	
12	Transformers	20,778,264	-	-	-	-	-	-	7,500,953	13,277,311	-	-	-	-	-	-	-	
13	Secondary Conductor&Eqpt	1,215,205	-	-	-	-	-	-	-	-	708,464	506,740	-	-	-	-	-	
14	Services	2,020,790	-	-	-	-	-	-	-	-	-	-	2,020,790	-	-	-	-	
15	Meters	4,544,442	-	-	-	-	-	-	-	-	-	-	-	4,544,442	-	-	-	
16	Street Lighting	2,215,553	-	-	-	-	-	-	-	-	-	-	-	-	2,215,553	-	-	
17	Subtotal Distribution	96,170,968	-	-	-	12,569,787	33,312,150	9,566,138	7,500,953	13,277,311	5,278,844	5,884,999	2,020,790	4,544,442	2,215,553	-	-	
18	Subttl Prod, Trans, & Dist	227,189,218	32,138,789	-	75,766,523	32,651,871	33,312,150	9,566,138	7,500,953	13,277,311	5,278,844	5,884,999	2,020,790	4,544,442	2,215,553	-	3,030,854	
19	General	25,144,749	1,664,749	-	10,311,823	1,291,113	2,838,804	815,210	639,218	1,131,470	449,854	501,509	172,208	606,044	188,806	4,424,635	109,306	
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Software - General	987,134	139,643	-	329,204	141,872	144,741	41,565	32,592	57,690	22,936	25,570	8,780	19,746	9,627	-	13,169	
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
24	Total Plant	253,321,102	33,943,181	-	86,407,551	34,084,855	36,295,695	10,422,913	8,172,763	14,466,470	5,751,634	6,412,079	2,201,779	5,170,232	2,413,985	4,424,635	3,153,329	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch G 4.1 L.9
2	Diesel	Production - Demand, Energy ratios Sch G 4.1 L.9
3	Subtotal Production	
	Transmission	
4	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
6	Subtotal Transmission	
	Distribution	
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.32
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.37
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.38
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.39
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch G 4.1 L.40
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.41
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	Subtotal Distribution	
18	Subttl Prod, Trans, & Dist	
19	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch G 2.4 L.11, 12
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
23	Software - Cust Acctng	
24	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Gas Turbines	10,673,663	10,673,663	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	384,172	384,172	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	11,057,835	11,057,835	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
4	Lines	3,536,019	-	-	3,536,019	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	86,402,412	-	-	73,946,857	12,394,404	-	-	-	-	-	-	-	-	-	-	61,151
6	Subtotal Transmission	89,938,431	-	-	77,482,876	12,394,404	-	-	-	-	-	-	-	-	-	-	61,151
Distribution																	
7	Substations	9,162,491	-	-	-	9,162,491	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	602,147	-	-	-	-	453,989	57,836	-	-	52,658	37,664	-	-	-	-	-
9	Poles	17,476,092	-	-	-	-	10,107,263	3,454,184	-	-	1,788,993	2,125,652	-	-	-	-	-
10	Primary Conductor & Eqpt	3,429,399	-	-	-	-	3,041,877	387,522	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	71,524	-	-	-	-	71,524	-	-	-	-	-	-	-	-	-	-
12	Transformers	9,301,909	-	-	-	-	-	-	3,357,989	5,943,920	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	322,268	-	-	-	-	-	-	-	-	187,882	134,386	-	-	-	-	-
14	Services	580,745	-	-	-	-	-	-	-	-	-	-	580,745	-	-	-	-
15	Meters	3,208,535	-	-	-	-	-	-	-	-	-	-	-	3,208,535	-	-	-
16	Street Lighting	1,011,870	-	-	-	-	-	-	-	-	-	-	-	-	1,011,870	-	-
17	Subtotal Distribution	45,166,980	-	-	-	9,162,491	13,674,652	3,899,543	3,357,989	5,943,920	2,029,533	2,297,702	580,745	3,208,535	1,011,870	-	-
18	Subttl Prod, Trans, & Dist	146,163,246	11,057,835	-	77,482,876	21,556,895	13,674,652	3,899,543	3,357,989	5,943,920	2,029,533	2,297,702	580,745	3,208,535	1,011,870	-	61,151
19	General	12,481,459	826,355	-	5,118,627	640,888	1,409,138	404,657	317,298	561,644	223,300	248,941	85,481	300,831	93,720	2,196,319	54,258
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	1,017,004	76,940	-	539,126	149,993	95,148	27,133	23,365	41,358	14,121	15,987	4,041	22,325	7,041	-	425
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Net Book Value	159,661,709	11,961,131	-	83,140,629	22,347,776	15,178,938	4,331,333	3,698,652	6,546,921	2,266,954	2,562,631	670,268	3,531,691	1,112,631	2,196,319	115,834

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Production																
1	Gas Turbine / Diesel	443,265	443,265	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	16,244	16,244	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	459,509	459,509	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	2,626,439	-	-	2,626,439	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	210,591	-	-	143,351	40,429	-	-	-	-	-	-	-	-	-	-	26,812
6	Other	100,147	-	-	76,509	20,279	-	-	-	-	-	-	-	-	-	-	3,359
7	Subtotal Transmission	2,937,178	-	-	2,846,299	60,708	-	-	-	-	-	-	-	-	-	-	30,171
	Distribution																
8	Other	2,155,257	-	-	-	295,669	783,575	225,017	176,439	312,311	124,170	138,428	47,533	-	52,115	-	-
9	Meters	167,282	-	-	-	-	-	-	-	-	-	-	-	167,282	-	-	-
10	Subtotal Distribution	2,322,539	-	-	-	295,669	783,575	225,017	176,439	312,311	124,170	138,428	47,533	167,282	52,115	-	-
11	Subttl Prod, Trans, & Dist	5,719,226	459,509	-	2,846,299	356,377	783,575	225,017	176,439	312,311	124,170	138,428	47,533	167,282	52,115	-	30,171
12	Customer Accounting	1,221,301	-	-	-	-	-	-	-	-	-	-	-	-	-	1,221,301	-
	Conservation and Demand Management	74,931	24,872	50,059													
	Administrative & General:																
	Plant-Related:																
13	Production	180,309	180,309	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	255,382	-	-	201,874	53,507	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	611,761	-	-	-	79,959	211,905	60,852	47,715	84,459	33,580	37,436	12,855	28,908	14,094	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn & General Plt	634,360	86,071	-	219,107	86,430	92,036	26,430	20,724	36,683	14,585	16,259	5,583	13,110	6,121	11,220	-
18	Property Insurance	214,760	45,082	-	108,716	45,268	3,786	1,087	852	1,509	600	669	230	808	252	5,901	-
	Revenue-Related:																
19	Municipal Tax	571,245	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	34,268	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	3,108,085	206,674	-	1,280,186	160,288	352,430	101,206	79,357	140,469	55,848	62,261	21,379	75,239	23,440	549,307	-
22	Prod, Trans & Distn Expense-Related	45,804	3,700	-	22,916	2,869	6,309	1,812	1,421	2,515	1,000	1,115	383	1,347	420	-	-
23	Subtotal Admin & General	5,655,974	521,835	-	1,832,800	428,322	666,466	191,387	150,069	265,635	105,612	117,739	40,429	119,412	44,326	566,428	-
	Total Operating & Maintenance Expenses	12,671,431	1,006,216	50,059	4,679,099	784,698	1,450,041	416,403	326,508	577,947	229,782	256,167	87,963	286,694	96,441	1,787,728	30,171

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense (CONTD.)

Line No.	1 Description	18 Revenue Related		19 PUB Assessment	20 Basis of Functional Classification
		Municipal Tax			
	Production				
1	Gas Turbine / Diesel	-	-		Production - Demand, Energy ratios Sch G 4.1 L.9
2	Other	-	-		Production - Demand, Energy ratios Sch G 4.1 L.9
3	Subtotal Production	-	-		
	Transmission				
4	Transmission Lines	-	-		Prorated on Transmission Lines Plant in Service - Sch G 2.2 L.4
5	Terminal Stations	-	-		Prorated on Transmission Terminal Stations Plant in Service - Sch G 2.2 L.5
6	Other	-	-		Prorated on Transmission Plant in Service - Sch G 2.2 L.6
7	Subtotal Transmission	-	-		
	Distribution				
8	Other	-	-		Prorated on Distribution Plant, excluding Meters - Sch G 2.2 L. 17, less L. 15
9	Meters	-	-		Meters - Customer
10	Subtotal Distribution	-	-		
11	Subttl Prod, Trans, & Dist	-	-		
12	Customer Accounting Conservation and Demand Management	-	-		Accounting - Customer
	Administrative & General:				
	Plant-Related:				
13	Production	-	-		Prorated on Production Plant in Service - Sch G 2.2 L.3
14	Transmission	-	-		Prorated on Transmission Plant in Service - Sch G 2.2 L. 6
15	Distribution	-	-		Prorated on Distribution Plant in Service - Sch G 2.2 L.17
16	Prod, Trans, Distn Plant	-	-		Prorated on Production, Transmission, Distribution Plant in Service - Sch G 2.2 L. 18
17	Prod, Trans, Distn & General Plt	-	-		Prorated on Production, Transmission, Distribution & General Plant in Service - Sch G 2.2 L.24
18	Property Insurance	-	-		Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch G 2.2 L.3, 5, 7, 19 - 20
	Revenue-Related:				
19	Municipal Tax	571,245	-		Revenue-related
20	PUB Assessment	-	34,268		Revenue-related
21	All Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 11, 12
22	Prod,Trans & Distn Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	571,245	34,268		
24	Total Operating & Maintenance Expenses	571,245	34,268		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected

Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Gas Turbines	323,490	323,490	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	17,541	17,541	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	341,031	341,031	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
4	Lines	86,938	-	-	86,938	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	2,242,671	-	-	1,800,904	439,240	-	-	-	-	-	-	-	-	-	-	2,528
6	Subtotal Transmission	2,329,609	-	-	1,887,841	439,240	-	-	-	-	-	-	-	-	-	-	2,528
Distribution																	
7	Substations	263,747	-	-	-	263,747	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	12,923	-	-	-	-	9,743	1,241	-	-	1,130	808	-	-	-	-	-
9	Poles	1,241,804	-	-	-	-	718,195	245,445	-	-	127,121	151,043	-	-	-	-	-
10	Primary Conductor & Equip	149,360	-	-	-	-	132,482	16,878	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	20,152	-	-	-	-	20,152	-	-	-	-	-	-	-	-	-	-
12	Transformers	520,645	-	-	-	-	-	-	187,953	332,692	-	-	-	-	-	-	-
13	Secondary Conductor & Equip	18,601	-	-	-	-	-	-	-	-	10,844	7,757	-	-	-	-	-
14	Services	36,575	-	-	-	-	-	-	-	-	-	-	36,575	-	-	-	-
15	Meters	240,366	-	-	-	-	-	-	-	-	-	-	-	240,366	-	-	-
16	Street Lighting	80,886	-	-	-	-	-	-	-	-	-	-	-	-	80,886	-	-
17	Subtotal Distribution	2,585,058	-	-	-	263,747	880,572	263,564	187,953	332,692	139,095	159,608	36,575	240,366	80,886	-	-
18	Subttl Prod, Trans, & Dist	5,255,698	341,031	-	1,887,841	702,988	880,572	263,564	187,953	332,692	139,095	159,608	36,575	240,366	80,886	-	2,528
19	General	937,122	62,044	-	384,312	48,119	105,800	30,382	23,823	42,169	16,766	18,691	6,418	22,587	7,037	164,902	4,074
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	GEC and AFUDC	29,095	1,888	-	10,451	3,892	4,875	1,459	1,040	1,842	770	884	202	1,331	448	-	14
22	Software - General	183,814	11,927	-	66,026	24,586	30,797	9,218	6,574	11,636	4,865	5,582	1,279	8,407	2,829	-	88
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Depreciation Expense	6,405,729	416,890	-	2,348,631	779,584	1,022,044	304,623	219,390	388,338	161,496	184,765	44,474	272,690	91,199	164,902	6,704

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
1	Average Net Book Value	159,661,709	11,961,131	-	83,140,629	22,347,776	15,178,938	4,331,333	3,698,652	6,546,921	2,266,954	2,562,631	670,268	3,531,691	1,112,631	2,196,319	115,834
2	Cash Working Capital	103,735	7,771	-	54,018	14,520	9,862	2,814	2,403	4,254	1,473	1,665	435	2,295	723	1,427	75
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	120,566	120,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	2,896,934	388,168	-	988,141	389,788	415,071	119,195	93,462	165,436	65,775	73,327	25,179	59,126	27,606	50,599	36,061
	Deferred Charges:																
	Foreign Exchange Loss and Regulatory																
7	Costs	7,674,183	574,915	-	3,996,177	1,074,152	729,580	208,187	177,777	314,680	108,962	123,174	32,217	169,752	53,479	105,567	5,568
8	Retire Asset Pool	8,203,333	614,556	-	4,271,721	1,148,217	779,886	222,542	190,035	336,377	116,475	131,667	34,438	181,456	57,166	112,846	5,951
9	Total Rate Base	178,660,460	13,667,107	-	92,450,686	24,974,453	17,113,337	4,884,070	4,162,329	7,367,668	2,559,639	2,892,463	762,537	3,944,320	1,251,605	2,466,758	163,489
10	Less: Rural Portion	-															
11	Rate Base Available for Equity Return	178,660,460	13,667,107	-	92,450,686	24,974,453	17,113,337	4,884,070	4,162,329	7,367,668	2,559,639	2,892,463	762,537	3,944,320	1,251,605	2,466,758	163,489
12	Return on Debt	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921
13	Return on Equity	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057
14	Return on Rate Base	8,718,630	666,955	-	4,511,593	1,218,753	835,131	238,343	203,122	359,542	124,910	141,152	37,212	192,483	61,078	120,378	7,978

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch G 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch G 2.2, L. 24
	Deterred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retire Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch G 1.1,p2,L.16
13	Return on Equity	L.11 x Sch G 1.1,p2,L.19
14	Return on Rate Base	

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount	Production Demand	Production Energy	Transmission Demand	Distribution										Accounting Customer	Specifically Assigned Customer
						Substations Demand	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wld Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Labrador Industrial Firm	-	317,009	2,026,309	298,387	-	-	-	-	-	-	-	-	-	-	-	-
3	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																	
4	1.1Domestic	-	741	2,552	698	673	673	316	636	316	636	316	316	316	-	316	-
5	1.1A Domestic All Electric	-	88,402	359,751	83,209	80,273	80,273	10,070	75,848	10,070	75,848	10,070	10,070	10,070	-	10,070	-
6	2.1GS 0-10 kW	-	914	4,960	861	830	830	429	785	429	785	429	804	804	-	429	-
7	2.2GS 10-100 kW	-	16,660	83,943	15,681	15,128	15,128	759	14,139	759	14,139	759	3,618	3,618	-	759	-
8	2.3GS 110-1,000 kVa	-	30,753	173,760	28,946	27,925	27,925	197	25,056	197	25,056	197	1,655	1,655	-	197	-
9	2.4GS Over 1,000 kVa	-	25,421	157,718	23,928	23,084	23,084	6	4,112	6	4,112	6	51	51	-	6	-
10	4.1Street and Area Lighting	-	268	1,085	252	243	243	398	230	398	230	398	-	-	1	398	-
11	Subtotal Rural	-	163,160	783,769	153,575	148,157	148,157	12,173	120,805	12,173	120,805	12,173	16,513	16,513	1	12,173	-
12	Total Labrador Interconnected	-	480,169	2,810,079	451,962	148,157	148,157	12,173	120,805	12,173	120,805	12,173	16,513	16,513	1	12,173	-
Ratios																	
13	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Labrador Industrial Firm	-	0.6602	0.7211	0.6602	-	-	-	-	-	-	-	-	-	-	-	-
15	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																	
16	1.1Domestic	-	0.0015	0.0009	0.0015	0.0045	0.0045	0.0259	0.0053	0.0259	0.0053	0.0259	0.0191	0.0191	-	0.0259	-
17	1.1A Domestic All Electric	-	0.1841	0.1280	0.1841	0.5418	0.5418	0.8272	0.6279	0.8272	0.6279	0.8272	0.6098	0.6098	-	0.8272	-
18	2.1GS 0-10 kW	-	0.0019	0.0018	0.0019	0.0056	0.0056	0.0352	0.0065	0.0352	0.0065	0.0352	0.0487	0.0487	-	0.0352	-
19	2.2GS 10-100 kW	-	0.0347	0.0299	0.0347	0.1021	0.1021	0.0623	0.1170	0.0623	0.1170	0.0623	0.2191	0.2191	-	0.0623	-
20	2.3GS 110-1,000 kVa	-	0.0640	0.0618	0.0640	0.1885	0.1885	0.0161	0.2074	0.0161	0.2074	0.0161	0.1002	0.1002	-	0.0161	-
21	2.4GS Over 1,000 kVa	-	0.0529	0.0561	0.0529	0.1558	0.1558	0.0005	0.0340	0.0005	0.0340	0.0005	0.0031	0.0031	-	0.0005	-
22	4.1Street and Area Lighting	-	0.0006	0.0004	0.0006	0.0016	0.0016	0.0327	0.0019	0.0327	0.0019	0.0327	-	-	1.0000	0.0327	-
23	Subtotal Rural	-	0.3398	0.2789	0.3398	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
24	Total Labrador Interconnected	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
Ratios Excluding Labrador Industrial																	
25	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																	
26	1.1Domestic	-	0.0045	0.0033	0.0045	0.0045	0.0045	0.0259	0.0053	0.0259	0.0053	0.0259	0.0191	0.0191	-	0.0259	-
27	1.1A Domestic All Electric	-	0.5418	0.4590	0.5418	0.5418	0.5418	0.8272	0.6279	0.8272	0.6279	0.8272	0.6098	0.6098	-	0.8272	-
28	2.1GS 0-10 kW	-	0.0056	0.0063	0.0056	0.0056	0.0056	0.0352	0.0065	0.0352	0.0065	0.0352	0.0487	0.0487	-	0.0352	-
29	2.2GS 10-100 kW	-	0.1021	0.1071	0.1021	0.1021	0.1021	0.0623	0.1170	0.0623	0.1170	0.0623	0.2191	0.2191	-	0.0623	-
30	2.3GS 110-1,000 kVa	-	0.1885	0.2217	0.1885	0.1885	0.1885	0.0161	0.2074	0.0161	0.2074	0.0161	0.1002	0.1002	-	0.0161	-
31	2.4GS Over 1,000 kVa	-	0.1558	0.2012	0.1558	0.1558	0.1558	0.0005	0.0340	0.0005	0.0340	0.0005	0.0031	0.0031	-	0.0005	-
32	4.1Street and Area Lighting	-	0.0016	0.0014	0.0016	0.0016	0.0016	0.0327	0.0019	0.0327	0.0019	0.0327	-	-	1.0000	0.0327	-
33	Subtotal Rural	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-
34	Total Labrador Interconnected	-	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1	Revenue Related	
		18 Municipal Tax (Prior Year (Rural Revenues)	19 PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	CFB - Goose Bay Secondary	-	-
2	Labrador Industrial Firm	-	-
3	Labrador Industrial Non-Firm	-	-
	Rural		
4	1.1Domestic	94,365	94,365
5	1.1A Domestic All Electric	10,520,637	10,520,637
6	2.1GS 0-10 kW	345,486	345,486
7	2.2GS 10-100 kW	2,208,779	2,208,779
8	2.3GS 110-1,000 kVa	3,539,649	3,539,649
9	2.4GS Over 1,000 kVa	3,243,034	3,243,034
10	4.1Street and Area Lighting	361,265	361,265
11	Subtotal Rural	20,313,216	20,313,216
12	Total Labrador Interconnected	20,313,216	20,313,216
	Ratios		
13	CFB - Goose Bay Secondary	-	-
14	Labrador Industrial Firm	-	-
15	Labrador Industrial Non-Firm	-	-
	Rural		
16	1.1Domestic	0.0046	0.0046
17	1.1A Domestic All Electric	0.5179	0.5179
18	2.1GS 0-10 kW	0.0170	0.0170
19	2.2GS 10-100 kW	0.1087	0.1087
20	2.3GS 110-1,000 kVa	0.1743	0.1743
21	2.4GS Over 1,000 kVa	0.1597	0.1597
22	4.1Street and Area Lighting	0.0178	0.0178
23	Subtotal Rural	1.0000	1.0000
24	Total Labrador Interconnected	1.0000	1.0000
	Ratios Excluding Labrador Industrial		
25	CFB - Goose Bay Secondary	-	-
	Rural		
26	1.1Domestic	0.0046	0.0046
27	1.1A Domestic All Electric	0.5179	0.5179
28	2.1GS 0-10 kW	0.0170	0.0170
29	2.2GS 10-100 kW	0.1087	0.1087
30	2.3GS 110-1,000 kVa	0.1743	0.1743
31	2.4GS Over 1,000 kVa	0.1597	0.1597
32	4.1Street and Area Lighting	0.0178	0.0178
33	Subtotal Rural	1.0000	1.0000

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service																		
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines (\$)		Line Transformers (\$)		Secondary Lines (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting (\$)			
1	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Labrador Industrial Firm	5,745,324	1,042,820	36,097	4,629,631	-	-	-	-	-	-	-	-	-	-	-	36,776	
3	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Rural:																		
4	1.1Domestic	160,727	4,783	3,425	10,828	7,097	10,558	17,376	2,869	24,995	1,922	10,621	2,525	10,670	-	50,253	-	
5	1.1A Domestic All Electric	9,049,493	570,294	482,877	1,291,031	846,159	1,258,792	554,611	342,074	797,785	229,186	339,002	80,587	340,549	-	1,603,964	-	
6	2.1GS 0-10 kW	237,724	5,899	6,657	13,353	8,752	13,020	23,600	3,538	33,947	2,370	14,425	6,438	27,207	-	68,252	-	
7	2.2GS 10-100 kW	1,431,773	107,473	112,673	243,298	159,461	237,222	41,775	63,768	60,091	42,724	25,535	28,955	122,359	-	120,815	-	
8	2.3GS 110-1,000 kVa	2,040,373	198,390	233,230	449,115	294,356	437,900	10,823	113,001	15,569	75,709	6,616	13,241	55,954	-	31,301	-	
9	2.4GS Over 1,000 kVa	1,483,657	163,997	211,697	371,255	243,326	361,985	330	18,543	475	12,424	202	404	1,708	-	956	-	
10	4.1Street and Area Lighting	343,518	1,729	1,457	3,915	2,566	3,817	21,920	1,037	31,531	695	13,399	-	-	187,324	63,394	-	
11	Subtotal Rural	14,747,265	1,052,566	1,052,016	2,382,795	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	-	
12	Total	20,492,589	2,095,386	1,088,113	7,012,426	1,561,716	2,323,294	670,436	544,830	964,394	365,030	409,800	132,150	558,447	187,324	1,938,935	36,776	
Allocated Return on Debt																		
13	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Labrador Industrial Firm	2,113,708	271,595	-	1,837,193	-	-	-	-	-	-	-	-	-	-	-	4,921	
15	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
16	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Rural:																		
17	1.1Domestic	28,200	635	-	4,297	3,416	2,341	3,810	660	5,748	406	2,257	439	2,268	-	1,924	-	
18	1.1A Domestic All Electric	1,926,396	75,738	-	512,324	407,298	279,094	121,613	78,661	183,454	48,373	72,022	13,997	72,400	-	61,422	-	
19	2.1GS 0-10 kW	40,058	783	-	5,299	4,213	2,887	5,175	814	7,806	500	3,065	1,118	5,784	-	2,614	-	
20	2.2GS 10-100 kW	327,927	14,273	-	96,549	76,756	52,596	9,160	14,664	13,818	9,017	5,425	5,029	26,013	-	4,626	-	
21	2.3GS 110-1,000 kVa	508,066	26,347	-	178,224	141,688	97,089	2,373	25,985	3,580	15,980	1,406	2,300	11,896	-	1,199	-	
22	2.4GS Over 1,000 kVa	374,069	21,779	-	147,326	117,125	80,258	72	4,264	109	2,622	43	70	363	-	37	-	
23	4.1Street and Area Lighting	59,255	230	-	1,554	1,235	846	4,807	239	7,251	147	2,847	-	-	37,673	2,428	-	
24	Subtotal Rural	3,263,972	139,785	-	945,573	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	-	
25	Total	5,377,680	411,380	-	2,782,766	751,731	515,111	147,011	125,286	221,767	77,045	87,063	22,952	118,724	37,673	74,249	4,921	
Allocated Return on Equity																		
26	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
27	Labrador Industrial Firm	1,313,168	168,732	-	1,141,379	-	-	-	-	-	-	-	-	-	-	-	3,057	
28	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Rural:																		
30	1.1Domestic	17,520	395	-	2,670	2,122	1,454	2,367	410	3,571	252	1,402	272	1,409	-	1,196	-	
31	1.1A Domestic All Electric	1,196,798	47,053	-	318,288	253,039	173,391	75,554	48,869	113,973	30,052	44,745	8,696	44,979	-	38,159	-	
32	2.1GS 0-10 kW	24,886	487	-	3,292	2,617	1,793	3,215	505	4,850	311	1,904	695	3,593	-	1,624	-	
33	2.2GS 10-100 kW	203,729	8,867	-	59,982	47,686	32,676	5,691	9,110	8,585	5,602	3,370	3,124	16,161	-	2,874	-	
34	2.3GS 110-1,000 kVa	315,642	16,368	-	110,724	88,025	60,318	1,474	16,144	2,224	9,928	873	1,429	7,390	-	745	-	
35	2.4GS Over 1,000 kVa	232,395	13,531	-	91,528	72,765	49,861	45	2,649	68	1,629	27	44	226	-	23	-	
36	4.1Street and Area Lighting	36,813	143	-	965	767	526	2,986	148	4,505	91	1,768	-	-	23,405	1,508	-	
37	Subtotal Rural	2,027,783	86,843	-	587,449	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	-	
38	Total	3,340,951	255,575	-	1,728,828	467,022	320,019	91,332	77,836	137,775	47,865	54,089	14,259	73,759	23,405	46,128	3,057	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	18	19	Basis of Proration
		Revenue Related		
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Rev Reqmt Excl Return			
1	CFB - Goose Bay Secondary	-	-	
2	Labrador Industrial Firm	-	-	
3	Labrador Industrial Non-Firm	-	-	
		-	-	
	Rural:			
4	1.1Domestic	2,645	159	
5	1.1A Domestic All Electric	294,892	17,690	
6	2.1GS 0-10 kW	9,684	581	
7	2.2GS 10-100 kW	61,912	3,714	
8	2.3GS 110-1,000 kVa	99,216	5,952	
9	2.4GS Over 1,000 kVa	90,902	5,453	
10	4.1Street and Area Lighting	10,126	607	
11	Subtotal Rural	569,376	34,156	
12	Total	569,376	34,156	
	Allocated Return on Debt			
13	CFB - Goose Bay Secondary	-	-	
14	Labrador Industrial Firm	-	-	
15	Labrador Industrial Non-Firm	-	-	
16	MFP Construction	-	-	
	Rural:			
17	1.1Domestic	-	-	
18	1.1A Domestic All Electric	-	-	
19	2.1GS 0-10 kW	-	-	
20	2.2GS 10-100 kW	-	-	
21	2.3GS 110-1,000 kVa	-	-	
22	2.4GS Over 1,000 kVa	-	-	
23	4.1Street and Area Lighting	-	-	
24	Subtotal Rural	-	-	
25	Total	-	-	
	Allocated Return on Equity			
26	CFB - Goose Bay Secondary	-	-	
27	Labrador Industrial Firm	-	-	
28	Labrador Industrial Non-Firm	-	-	
29	MFP Construction	-	-	
	Rural:			
30	1.1Domestic	-	-	
31	1.1A Domestic All Electric	-	-	
32	2.1GS 0-10 kW	-	-	
33	2.2GS 10-100 kW	-	-	
34	2.3GS 110-1,000 kVa	-	-	
35	2.4GS Over 1,000 kVa	-	-	
36	4.1Street and Area Lighting	-	-	
37	Subtotal Rural	-	-	
38	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
39	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Labrador Industrial Firm	9,172,200	1,483,146	36,097	7,608,202	-	-	-	-	-	-	-	-	-	-	-	44,754
41	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
43	1.1Domestic	206,448	5,813	3,425	17,795	12,636	14,353	23,554	3,939	34,314	2,580	14,280	3,236	14,347	-	53,373	-
44	1.1A Domestic All Electric	12,172,687	693,085	482,877	2,121,643	1,506,496	1,711,278	751,777	469,605	1,095,213	307,611	455,769	103,279	457,928	-	1,703,545	-
45	2.1GS 0-10 kW	302,668	7,169	6,657	21,944	15,582	17,700	31,990	4,857	46,604	3,182	19,394	8,251	36,584	-	72,489	-
46	2.2GS 10-100 kW	1,963,429	130,613	112,673	399,828	283,903	322,494	56,626	87,541	82,494	57,343	34,330	37,108	164,533	-	128,316	-
47	2.3GS 110-1,000 kVa	2,864,082	241,106	233,230	738,063	524,070	595,308	14,671	155,130	21,373	101,617	8,894	16,969	75,240	-	33,245	-
48	2.4GS Over 1,000 kVa	2,090,121	199,307	211,697	610,110	433,215	492,103	448	25,456	653	16,675	272	518	2,297	-	1,015	-
49	4.1Street and Area Lighting	439,585	2,102	1,457	6,434	4,568	5,189	29,713	1,424	43,286	933	18,014	-	-	248,403	67,330	-
50	Subtotal Rural	20,039,020	1,279,194	1,052,016	3,915,817	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	-
51	Total	29,211,220	2,762,341	1,088,113	11,524,019	2,780,469	3,158,425	908,778	747,952	1,323,937	489,940	550,952	169,361	750,929	248,403	2,059,313	44,754
Re-classification of Revenue-Related																	
52	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Labrador Industrial Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
56	1.1Domestic	-	80	47	245	174	198	324	54	472	36	197	45	198	-	735	-
57	1.1A Domestic All Electric	0	18,267	12,727	55,917	39,705	45,102	19,814	12,377	28,865	8,107	12,012	2,722	12,069	-	44,898	-
58	2.1GS 0-10 kW	-	252	234	770	547	621	1,123	171	1,636	112	681	290	1,284	-	2,545	-
59	2.2GS 10-100 kW	0	4,517	3,896	13,826	9,817	11,152	1,958	3,027	2,853	1,983	1,187	1,283	5,690	-	4,437	-
60	2.3GS 110-1,000 kVa	(0)	9,191	8,891	28,134	19,977	22,693	559	5,913	815	3,874	339	647	2,868	-	1,267	-
61	2.4GS Over 1,000 kVa	(0)	9,632	10,231	29,485	20,936	23,782	22	1,230	32	806	13	25	111	-	49	-
62	4.1Street and Area Lighting	0	53	36	161	114	130	744	36	1,083	23	451	-	-	6,217	1,685	-
63	Subtotal Rural	0	41,991	36,062	128,540	91,271	103,678	24,544	22,808	35,756	14,940	14,880	5,011	22,219	6,217	55,616	-
64	Total	0	41,991	36,062	128,540	91,271	103,678	24,544	22,808	35,756	14,940	14,880	5,011	22,219	6,217	55,616	-
Total Allocated Revenue Requirement																	
65	CFB - Goose Bay Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Labrador Industrial Firm	9,172,200	1,483,146	36,097	7,608,202	-	-	-	-	-	-	-	-	-	-	-	44,754
67	Labrador Industrial Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	MFP Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural:																	
69	1.1Domestic	206,448	5,893	3,472	18,040	12,809	14,551	23,878	3,993	34,786	2,616	14,476	3,280	14,545	-	54,108	-
70	1.1A Domestic All Electric	12,172,687	711,352	495,604	2,177,560	1,546,201	1,756,380	771,591	481,981	1,124,078	315,718	467,781	106,001	469,997	-	1,748,443	-
71	2.1GS 0-10 kW	302,668	7,420	6,891	22,715	16,129	18,321	33,113	5,028	48,240	3,293	20,075	8,541	37,868	-	75,034	-
72	2.2GS 10-100 kW	1,963,429	135,130	116,569	413,654	293,720	333,646	58,584	90,568	85,347	59,326	35,517	38,391	170,222	-	132,753	-
73	2.3GS 110-1,000 kVa	2,864,082	250,296	242,120	766,197	544,047	618,000	15,230	161,043	22,188	105,490	9,233	17,616	78,108	-	34,512	-
74	2.4GS Over 1,000 kVa	2,090,121	208,939	221,928	639,595	454,152	515,886	470	26,686	684	17,481	285	543	2,408	-	1,064	-
75	4.1Street and Area Lighting	439,585	2,154	1,493	6,595	4,683	5,319	30,456	1,460	44,370	956	18,464	-	-	254,620	69,015	-
76	Subtotal Rural	20,039,020	1,321,185	1,088,077	4,044,357	2,871,740	3,262,103	933,322	770,760	1,359,693	504,881	565,832	174,373	773,149	254,620	2,114,930	-
77	Total	29,211,220	2,804,331	1,124,174	11,652,559	2,871,740	3,262,103	933,322	770,760	1,359,693	504,881	565,832	174,373	773,149	254,620	2,114,930	44,754

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Interconnected

Allocation of Functionalized Amounts to Classes of Service (CONT'D.)				
	1	18	19	
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Proration
		(\$)	(\$)	
	Total Revenue Requirement			
39	CFB - Goose Bay Secondary	-	-	
40	Labrador Industrial Firm	-	-	
41	Labrador Industrial Non-Firm	-	-	
42	MFP Construction	-	-	
	Rural:			
43	1.1Domestic	2,645	159	
44	1.1A Domestic All Electric	294,892	17,690	
45	2.1GS 0-10 kW	9,684	581	
46	2.2GS 10-100 kW	61,912	3,714	
47	2.3GS 110-1,000 kVa	99,216	5,952	
48	2.4GS Over 1,000 kVa	90,902	5,453	
49	4.1Street and Area Lighting	10,126	607	
50	Subtotal Rural	569,376	34,156	
51	Total	569,376	34,156	
	Re-classification of Revenue-Related			
52	CFB - Goose Bay Secondary	-	-	Re-classification to demand, energy and customer is based on rate class revenue
53	Labrador Industrial Firm	-	-	requirements excluding revenue-related items.
54	Labrador Industrial Non-Firm	-	-	
55	MFP Construction	-	-	
	Rural:			
56	1.1Domestic	(2,645)	(159)	
57	1.1A Domestic All Electric	(294,892)	(17,690)	
58	2.1GS 0-10 kW	(9,684)	(581)	
59	2.2GS 10-100 kW	(61,912)	(3,714)	
60	2.3GS 110-1,000 kVa	(99,216)	(5,952)	
61	2.4GS Over 1,000 kVa	(90,902)	(5,453)	
62	4.1Street and Area Lighting	(10,126)	(607)	
63	Subtotal Rural	(569,376)	(34,156)	
64	Total	(569,376)	(34,156)	
	Total Allocated Revenue Requirement			
65	CFB - Goose Bay Secondary	-	-	
66	Labrador Industrial Firm	-	-	
67	Labrador Industrial Non-Firm	-	-	
68	MFP Construction	-	-	
	Rural:			
69	1.1Domestic	-	-	
70	1.1A Domestic All Electric	-	-	
71	2.1GS 0-10 kW	-	-	
72	2.2GS 10-100 kW	-	-	
73	2.3GS 110-1,000 kVa	-	-	
74	2.4GS Over 1,000 kVa	-	-	
75	4.1Street and Area Lighting	-	-	
76	Subtotal Rural	-	-	
77	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmissior Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)					
	Expenses																
1	Operating & Maintenance	5,763,854	2,690,721	1,634,887	-	98,697	472,156	151,456	59,802	105,854	97,480	105,379	51,148	37,549	44,310	171,374	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	2,124,200	-	2,124,200	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	177,100	-	177,100	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,117,417	550,822	336,417	-	36,651	72,856	23,537	9,703	17,175	13,541	15,252	6,046	11,278	16,044	8,094	-
	Expense Credits																
8	Sundry	(18,852)	(8,800)	(5,347)	-	(323)	(1,544)	(495)	(196)	(346)	(319)	(345)	(167)	(123)	(145)	(561)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(20,860)	-	-	-	-	(12,065)	(4,123)	-	-	(2,135)	(2,537)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(216)	-	-	-	-	-	-	-	-	-	-	-	-	-	(216)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(39,928)	(8,800)	(5,347)	-	(323)	(13,609)	(4,618)	(196)	(346)	(2,454)	(2,882)	(167)	(123)	(145)	(777)	-
18	Subtotal Expenses	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-
21	Return on Debt	778,420	388,659	243,978	-	36,330	42,855	13,759	5,976	10,577	8,040	8,992	4,130	5,200	7,172	2,753	-
22	Return on Equity	483,603	241,459	151,574	-	22,570	26,624	8,548	3,712	6,571	4,995	5,586	2,566	3,230	4,456	1,711	-
23	Total Revenue Requirement	10,404,667	3,862,861	4,662,809	-	193,925	600,882	192,682	78,997	139,832	121,602	132,328	63,723	57,134	71,837	183,156	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		20 Basis of Functional Classification
		19 Municipal Tax	PUB Assessment	
	Expenses			
1	Operating & Maintenance	40,605	2,436	Carryforward from Sch G 2.4 L.25
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	
7	Depreciation	-	-	Carryforward from Sch G 2.5 L.23
	Expense Credits			
8	Sundry	(133)	(8)	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.25
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch G 2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.25
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.25
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch G 4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch G 4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	Total Expense Credits	(133)	(8)	
18	Subtotal Expenses	40,472	2,428	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch G 2.3 L.23
20	Subtotal Revenue Requirement Ex. Return	40,472	2,428	
21	Return on Debt	-	-	Prorated on Rate Base - Sch G 2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch G 2.6 L.11
23	Total Revenue Requirement	40,472	2,428	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
Production																	
1	Diesel	8,490,207	5,264,340	3,225,867	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	8,490,207	5,264,340	3,225,867	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	651,069	121,854	-	-	529,215	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	32,475	-	-	-	-	24,484	3,119	-	-	2,840	2,031	-	-	-	-	-
8	Poles	3,975,794	-	-	-	-	2,299,392	785,824	-	-	406,994	483,584	-	-	-	-	-
9	Primary Conductor & Equipment	253,596	-	-	-	-	224,940	28,656	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	894,252	-	-	-	-	-	-	322,825	571,427	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	199,639	-	-	-	-	-	-	-	-	116,390	83,250	-	-	-	-	-
13	Services	276,111	-	-	-	-	-	-	-	-	-	-	276,111	-	-	-	-
14	Meters	196,359	-	-	-	-	-	-	-	-	-	-	-	196,359	-	-	-
15	Street Lighting	239,198	-	-	-	-	-	-	-	-	-	-	-	-	239,198	-	-
16	Subtotal Distribution	6,718,493	121,854	-	-	529,215	2,548,816	817,599	322,825	571,427	526,224	568,865	276,111	196,359	239,198	-	-
17	Subttl Prod, Trans, & Dist	15,208,700	5,386,194	3,225,867	-	529,215	2,548,816	817,599	322,825	571,427	526,224	568,865	276,111	196,359	239,198	-	-
18	General	3,753,373	2,029,573	1,240,180	-	24,777	119,332	38,279	15,114	26,753	24,637	26,633	12,927	10,376	11,199	173,592	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	66,082	23,403	14,016	-	2,299	11,075	3,552	1,403	2,483	2,286	2,472	1,200	853	1,039	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Plant	19,028,155	7,439,171	4,480,064	-	556,291	2,679,223	859,430	339,342	600,663	553,147	597,970	290,238	207,588	251,437	173,592	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated

Functional Classification of Plant in Service for the Allocation of O&M Expense (CONTD.)

1

18

Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch G 4.1 L.6
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch G 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch G 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	15,938,486	9,882,633	6,055,853	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	15,938,486	9,882,633	6,055,853	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	1,012,596	14,673	-	-	997,923	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	7,638	-	-	-	-	5,759	734	-	-	668	478	-	-	-	-	-
8	Poles	1,747,765	-	-	-	-	1,010,817	345,449	-	-	178,915	212,584	-	-	-	-	-
9	Primary Conductor & Equipment	115,113	-	-	-	-	102,105	13,008	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	434,841	-	-	-	-	-	-	156,978	277,864	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	49,456	-	-	-	-	-	-	-	-	28,833	20,623	-	-	-	-	-
13	Services	106,892	-	-	-	-	-	-	-	-	-	-	106,892	-	-	-	-
14	Meters	138,636	-	-	-	-	-	-	-	-	-	-	-	138,636	-	-	-
15	Street Lighting	192,904	-	-	-	-	-	-	-	-	-	-	-	-	192,904	-	-
16	Subtotal Distribution	3,805,842	14,673	-	-	997,923	1,118,681	359,191	156,978	277,864	208,416	233,685	106,892	138,636	192,904	-	-
17	Subttl Prod, Trans, & Dist	19,744,328	9,897,307	6,055,853	-	997,923	1,118,681	359,191	156,978	277,864	208,416	233,685	106,892	138,636	192,904	-	-
18	General	1,636,872	885,111	540,851	-	10,805	52,041	16,694	6,591	11,667	10,744	11,615	5,638	4,525	4,884	75,705	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	137,381	68,865	42,137	-	6,944	7,784	2,499	1,092	1,933	1,450	1,626	744	965	1,342	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Net Book Value	21,518,581	10,851,283	6,638,840	-	1,015,672	1,178,506	378,384	164,661	291,464	220,610	246,926	113,273	144,126	199,131	75,705	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
						Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Production																
1	Diesel	2,065,682	1,280,823	784,859	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	208,062	129,008	79,053	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	2,273,744	1,409,831	863,912	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	212,712	3,974	-	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	-	7,801	-	-
9	Meters	7,228	-	-	-	-	-	-	-	-	-	-	-	7,228	-	-	-
10	Subtotal Distribution	219,940	3,974	-	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	7,228	7,801	-	-
11	Subttl Prod, Trans, & Dist	2,493,683	1,413,805	863,912	-	17,260	83,127	26,665	10,529	18,636	17,162	18,553	9,005	7,228	7,801	-	-
12	Customer Accounting	120,925	-	-	-	-	-	-	-	-	-	-	-	-	-	120,925	-
	Administrative & General:																
	Plant-Related:																
13	Production	962,970	597,088	365,882	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	862,064	15,635	-	-	67,905	327,044	104,908	41,422	73,321	67,521	72,992	35,428	25,195	30,692	-	-
16	Prod, Trans, Distn Plant	157,713	55,855	33,452	-	5,488	26,431	8,478	3,348	5,926	5,457	5,899	2,863	2,036	2,480	-	-
17	Prod, Trans, Distn and Gen Plt	1,547	605	364	-	45	218	70	28	49	45	49	24	17	20	14	-
18	Property Insurance	16,132	9,277	5,587	-	693	149	48	19	33	31	33	16	13	14	217	-
	Revenue Related:																
20	Municipal Tax	40,605	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	PUB Assessment	2,436	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	All Expense-Related	1,085,807	587,132	358,770	-	7,168	34,521	11,074	4,372	7,739	7,127	7,705	3,740	3,002	3,240	50,218	-
23	Prod, Trans, and Distn Expense-Related	19,971	11,323	6,919	-	138	666	214	84	149	137	149	72	58	62	-	-
24	Subtotal Admin & General	3,149,246	1,276,915	770,974	-	81,437	389,029	124,791	49,273	87,218	80,318	86,827	42,143	30,321	36,509	50,450	-
25	Total Operating & Maintenance Expenses	5,763,854	2,690,721	1,634,887	-	98,697	472,156	151,456	59,802	105,854	97,480	105,379	51,148	37,549	44,310	171,374	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

		18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch G 4.1 L6
2	Other	-	-	Production - Demand, Energy ratios Sch G 4.1 L6
3	Subtotal Production	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch G 2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch G 2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.5
7	Subtotal Transmission	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch G 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	Subtotal Distribution	-	-	
11	Subttl Prod, Trans, & Dist	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch G 2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch G 2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch G 2.2 L.17
17	Prod, Trans, Distn and Gen Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch G 2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch G 2.2 L.2, 4, 6, 18 - 19
19	Revenue Related:			
20	Municipal Tax	40,605	-	Revenue-related
21	PUB Assessment	-	2,436	Revenue-related
22	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
23	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
24	Subtotal Admin & General	40,605	2,436	
25	Total Operating & Maintenance Expenses	40,605	2,436	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Depreciation Expense

1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	705,506	437,448	268,058	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	705,506	437,448	268,058	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substn Struct & Eqpt	35,648	1,494	-	-	34,153	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	213	-	-	-	-	160	20	-	-	19	13	-	-	-	-	-
8	Poles	102,292	-	-	-	-	59,161	20,218	-	-	10,471	12,442	-	-	-	-	-
9	Primary Conductor & Equipment	6,118	-	-	-	-	5,427	691	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	23,984	-	-	-	-	-	-	8,658	15,326	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	2,459	-	-	-	-	-	-	-	-	1,434	1,025	-	-	-	-	-
13	Services	5,237	-	-	-	-	-	-	-	-	-	-	5,237	-	-	-	-
14	Meters	10,386	-	-	-	-	-	-	-	-	-	-	-	10,386	-	-	-
15	Street Lighting	14,935	-	-	-	-	-	-	-	-	-	-	-	-	14,935	-	-
16	Subtotal Distribution	201,272	1,494	-	-	34,153	64,748	20,930	8,658	15,326	11,924	13,481	5,237	10,386	14,935	-	-
17	Subtotal Prod Tran & Dist	906,778	438,942	268,058	-	34,153	64,748	20,930	8,658	15,326	11,924	13,481	5,237	10,386	14,935	-	-
18	General	175,004	94,630	57,824	-	1,155	5,564	1,785	705	1,247	1,149	1,242	603	484	522	8,094	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	3,921	1,898	1,159	-	148	280	91	37	66	52	58	23	45	65	-	-
21	Software - General	31,714	15,352	9,375	-	1,194	2,265	732	303	536	417	471	183	363	522	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	1,117,417	550,822	336,417	-	36,651	72,856	23,537	9,703	17,175	13,541	15,252	6,046	11,278	16,044	8,094	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmissior Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)					
1	Average Net Book Value	21,518,581	10,851,283	6,638,840	-	1,015,672	1,178,506	378,384	164,661	291,464	220,610	246,926	113,273	144,126	199,131	75,705	-
2	Cash Working Capital	13,981	7,050	4,313	-	660	766	246	107	189	143	160	74	94	129	49	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	206,653	-	206,653	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	217,603	85,073	51,233	-	6,362	30,639	9,828	3,881	6,869	6,326	6,838	3,319	2,374	2,875	1,985	-
	Deferred Charges: Foreign Exchange Loss and Regulatory																
7	Costs	1,034,296	521,570	319,098	-	48,819	56,645	18,187	7,914	14,009	10,604	11,869	5,445	6,927	9,571	3,639	-
8	Retired Asset Pool	2,870,021	1,447,280	885,449	-	135,464	157,182	50,467	21,962	38,874	29,424	32,934	15,108	19,223	26,559	10,097	-
9	Total Rate Base	25,861,135	12,912,256	8,105,587	-	1,206,976	1,423,738	457,111	198,525	351,406	267,107	298,727	137,218	172,743	238,266	91,475	-
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rate Base Available for Equity Return	25,861,135	12,912,256	8,105,587	-	1,206,976	1,423,738	457,111	198,525	351,406	267,107	298,727	137,218	172,743	238,266	91,475	-
12	Return on Debt	778,420	388,659	243,978	-	36,330	42,855	13,759	5,976	10,577	8,040	8,992	4,130	5,200	7,172	2,753	-
13	Return on Equity	483,603	241,459	151,574	-	22,570	26,624	8,548	3,712	6,571	4,995	5,586	2,566	3,230	4,456	1,711	-
14	Return on Rate Base	1,262,023	630,118	395,553	-	58,900	69,478	22,307	9,688	17,149	13,035	14,578	6,696	8,430	11,627	4,464	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch G 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch G 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch G 1.1,p2,L.16
13	Return on Equity	L.11 x Sch G 1.1,p2,L.19
14	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Basis of Allocation to Classes of Service

[illegible]

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	658,743	658,743
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	43,910	43,910
4	2.1 GS 0-10 kW	205,170	205,170
5	2.2 GS 10-100 kW	491,702	491,702
6	2.3 GS 110-1,000 kVa	-	-
7	2.4 GS Over 1,000 kVa	-	-
8	4.1 Street and Area Lighting	38,040	38,040
9	4.1G Gov't Street and Area Lighting	6,323	6,323
10	Total	1,443,889	1,443,889
	Ratios		
11	1.2 Domestic Diesel	0.4562	0.4562
12	1.2G Government Domestic Diesel	-	-
13	1.23 Churches, Schools & Com Halls	0.0304	0.0304
14	2.1 GS 0-10 kW	0.1421	0.1421
15	2.2 GS 10-100 kW	0.3405	0.3405
16	2.3 GS 110-1,000 kVa	-	-
17	2.4 GS Over 1,000 kVa	-	-
18	4.1 Street and Area Lighting	0.0263	0.0263
19	4.1G Gov't Street and Area Lighting	0.0044	0.0044

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Allocated Revenue Requirement Excluding Return																		
1	1.2 Domestic Diesel	6,757,294	2,531,252	2,982,840	-	105,725	416,091	139,262	54,270	100,280	85,008	96,247	43,519	37,167	-	146,060	-	
2	1.2G Government Domestic Diesel	48,553	19,622	20,707	-	820	3,226	767	421	553	659	530	240	205	-	805	-	
3	1.23 Churches, Schools & Com Halls	325,166	95,658	187,724	-	3,995	15,724	3,836	2,051	2,763	3,213	2,651	1,199	1,024	-	4,024	-	
4	2.1 GS 0-10 kW	731,952	183,957	420,985	-	7,683	30,239	16,023	3,944	11,538	6,178	11,074	9,401	8,029	-	16,805	-	
5	2.2 GS 10-100 kW	1,138,127	382,631	629,811	-	15,982	62,898	1,790	8,204	1,289	12,850	1,237	2,669	2,279	-	1,878	-	
6	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
8	4.1 Street and Area Lighting	141,363	19,622	25,189	-	820	3,226	8,696	421	6,262	659	6,010	-	-	60,209	9,120	-	
9	4.1G Gov't Street and Area Lighting	188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	Total	9,142,643	3,232,743	4,267,256	-	135,025	531,404	170,375	69,309	122,683	108,567	117,750	57,027	48,704	60,209	178,692	-	
Allocated Return on Debt and Equity																		
11	1.2 Domestic Diesel	947,551	493,385	276,494	-	46,119	54,402	18,233	7,586	14,017	10,206	11,916	5,110	6,433	-	3,649	-	
12	1.2G Government Domestic Diesel	6,911	3,825	1,919	-	358	422	100	59	-	79	66	28	35	-	20	-	
13	1.23 Churches, Schools & Com Halls	42,153	18,645	17,401	-	1,743	2,056	502	287	386	386	328	141	177	-	101	-	
14	2.1 GS 0-10 kW	91,473	35,856	39,023	-	3,352	3,954	2,098	551	1,613	742	1,371	1,104	1,390	-	420	-	
15	2.2 GS 10-100 kW	152,169	74,582	58,380	-	6,972	8,224	234	1,147	180	1,543	153	313	395	-	47	-	
16	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	4.1 Street and Area Lighting	21,690	3,825	2,335	-	358	422	1,139	59	875	79	744	-	-	11,627	228	-	
19	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Total	1,261,946	630,118	395,553	-	58,900	69,478	22,307	9,688	17,071	13,035	14,578	6,696	8,430	11,627	4,464	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

		18	19	
Line No.	Description	Revenue Related		Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	18,464	1,108	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	1,231	74	
4	2.1 GS 0-10 kW	5,751	345	
5	2.2 GS 10-100 kW	13,782	827	
6	2.3 GS 110-1,000 kVa	-	-	
7	2.4 GS Over 1,000 kVa	-	-	
8	4.1 Street and Area Lighting	1,066	64	
9	4.1G Gov't Street and Area Lighting	177	11	
10	Total	40,472	2,428	
	Allocated Return on Debt and Equity			
11	1.2 Domestic Diesel	-	-	
12	1.2G Government Domestic Diesel	-	-	
13	1.23 Churches, Schools & Com Halls	-	-	
14	2.1 GS 0-10 kW	-	-	
15	2.2 GS 10-100 kW	-	-	
16	2.3 GS 110-1,000 kVa	-	-	
17	2.4 GS Over 1,000 kVa	-	-	
18	4.1 Street and Area Lighting	-	-	
19	4.1G Gov't Street and Area Lighting	-	-	
20	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmisssior Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Total Revenue Requirement																	
21	1.2 Domestic Diesel	7,704,844	3,024,638	3,259,334	-	151,844	470,493	157,496	61,855	114,297	95,215	108,163	48,629	43,600	-	149,709	-
22	1.2G Government Domestic Diesel	55,464	23,447	22,627	-	1,177	3,647	868	479	553	738	596	268	240	-	825	-
23	1.23 Churches, Schools & Com Halls	367,319	114,303	205,125	-	5,738	17,780	4,339	2,338	3,149	3,598	2,980	1,340	1,201	-	4,124	-
24	2.1 GS 0-10 kW	823,425	219,814	460,008	-	11,035	34,193	18,121	4,495	13,151	6,920	12,445	10,505	9,418	-	17,225	-
25	2.2 GS 10-100 kW	1,290,296	457,213	688,192	-	22,953	71,121	2,025	9,350	1,469	14,393	1,391	2,982	2,674	-	1,925	-
26	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	4.1 Street and Area Lighting	163,053	23,447	27,524	-	1,177	3,647	9,834	479	7,137	738	6,754	-	-	71,837	9,348	-
29	4.1G Gov't Street and Area Lighting	188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total	10,404,589	3,862,861	4,662,809	-	193,925	600,882	192,682	78,997	139,755	121,602	132,328	63,723	57,134	71,837	183,156	-
Re-classification of Revenue-Related																	
31	1.2 Domestic Diesel	(0)	7,703	8,301	-	387	1,198	401	158	291	242	275	124	111	-	381	-
32	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	1.23 Churches, Schools & Com Halls	-	407	731	-	20	63	15	8	11	13	11	5	4	-	15	-
34	2.1 GS 0-10 kW	-	1,639	3,431	-	82	255	135	34	98	52	93	78	70	-	128	-
35	2.2 GS 10-100 kW	-	5,236	7,881	-	263	814	23	107	17	165	16	34	31	-	22	-
36	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	4.1 Street and Area Lighting	0	164	192	-	8	25	69	3	50	5	47	-	-	501	65	-
39	4.1G Gov't Street and Area Lighting	(188)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Total	(188)	15,149	20,536	-	761	2,357	644	310	467	477	442	241	216	501	612	-
Total Allocated Revenue Requirement																	
41	1.2 Domestic Diesel	7,704,844	3,032,340	3,267,635	-	152,231	471,692	157,897	62,013	114,588	95,457	108,438	48,753	43,711	-	150,090	-
42	1.2G Government Domestic Diesel	55,464	23,447	22,627	-	1,177	3,647	868	479	553	738	596	268	240	-	825	-
43	1.23 Churches, Schools & Com Halls	367,319	114,711	205,856	-	5,759	17,844	4,354	2,346	3,160	3,611	2,990	1,344	1,205	-	4,139	-
44	2.1 GS 0-10 kW	823,425	221,453	463,439	-	11,117	34,448	18,256	4,529	13,249	6,971	12,538	10,583	9,489	-	17,353	-
45	2.2 GS 10-100 kW	1,290,296	462,449	696,073	-	23,216	71,936	2,048	9,457	1,486	14,558	1,406	3,016	2,704	-	1,947	-
46	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	4.1 Street and Area Lighting	163,053	23,610	27,716	-	1,185	3,673	9,903	483	7,187	743	6,801	-	-	72,338	9,413	-
49	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Total	10,404,402	3,878,010	4,683,345	-	194,685	603,239	193,326	79,307	140,222	122,079	132,770	63,964	57,350	72,338	183,767	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	18	19	Basis of Proration
		Revenue Related		
		Municipal Tax (\$)	PUB Assessment (\$)	
	Total Revenue Requirement			
21	1.2 Domestic Diesel	18,464	1,108	
22	1.2G Government Domestic Diesel	-	-	
23	1.23 Churches, Schools & Com Halls	1,231	74	
24	2.1 GS 0-10 kW	5,751	345	
25	2.2 GS 10-100 kW	13,782	827	
26	2.3 GS 110-1,000 kVa	-	-	
27	2.4 GS Over 1,000 kVa	-	-	
28	4.1 Street and Area Lighting	1,066	64	
29	4.1G Gov't Street and Area Lighting	177	11	
30	Total	40,472	2,428	
	Re-classification of Revenue-Related			
31	1.2 Domestic Diesel	(18,464)	(1,108)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
32	1.2G Government Domestic Diesel	-	-	
33	1.23 Churches, Schools & Com Halls	(1,231)	(74)	
34	2.1 GS 0-10 kW	(5,751)	(345)	
35	2.2 GS 10-100 kW	(13,782)	(827)	
36	2.3 GS 110-1,000 kVa	-	-	
37	2.4 GS Over 1,000 kVa	-	-	
38	4.1 Street and Area Lighting	(1,066)	(64)	
39	4.1G Gov't Street and Area Lighting	(177)	(11)	
40	Total	(40,472)	(2,428)	
	Total Allocated Revenue Requirement			
41	1.2 Domestic Diesel	-	-	
42	1.2G Government Domestic Diesel	-	-	
43	1.23 Churches, Schools & Com Halls	-	-	
44	2.1 GS 0-10 kW	-	-	
45	2.2 GS 10-100 kW	-	-	
46	2.3 GS 110-1,000 kVa	-	-	
47	2.4 GS Over 1,000 kVa	-	-	
48	4.1 Street and Area Lighting	-	-	
49	4.1G Gov't Street and Area Lighting	-	-	
50	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
	Expenses																	
1	Operating & Maintenance	15,269,542	5,991,478	6,961,699	-	83,194	565,904	166,641	72,366	128,094	90,533	101,676	47,574	70,738	22,397	687,523	-	
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	Fuels-Diesel	17,415,200	-	17,415,200	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Power Purchases-Other	309,793	-	309,793	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	Depreciation	5,466,481	2,204,841	2,565,232	-	37,836	246,484	74,299	39,408	69,755	39,341	44,891	19,722	58,914	28,853	36,904	-	
	Expense Credits																	
8	Sundry	(49,941)	(19,596)	(22,769)	-	(272)	(1,851)	(545)	(237)	(419)	(296)	(333)	(156)	(231)	(73)	(2,249)	-	
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Pole Attachments	(107,593)	-	-	-	-	(62,226)	(21,266)	-	-	(11,014)	(13,087)	-	-	-	-	-	
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Application Fees	(1,176)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,176)	-	
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	Total Expense Credits	(158,711)	(19,596)	(22,769)	-	(272)	(64,077)	(21,811)	(237)	(419)	(11,310)	(13,419)	(156)	(231)	(73)	(3,425)	-	
18	Subtotal Expenses	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-	
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Subtotal Revenue Requirement Ex. Return	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-	
21	Return on Debt	3,616,593	1,400,804	1,802,059	-	37,339	142,825	42,315	27,122	48,008	22,662	25,628	15,165	27,260	10,894	14,514	-	
22	Return on Equity	2,246,853	870,267	1,119,551	-	23,197	88,732	26,289	16,850	29,825	14,079	15,922	9,421	16,935	6,768	9,017	-	
23	Total Revenue Requirement	44,165,752	10,447,794	30,150,766	-	181,293	979,867	287,733	155,509	275,264	155,305	174,698	91,727	173,615	68,839	744,534	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 20 Basis of Functional Classification
		Municipal Tax	PUB Assessment	
	Expenses			
1	Operating & Maintenance	263,893	15,830	Carryforward from Sch G 2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch G 4.4 L.20
7	Depreciation	-	-	Carryforward from Sch G 2.5 L.23
	Expense Credits			
8	Sundry	(863)	(52)	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch G 2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch G 4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch G 4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	Total Expense Credits	(863)	(52)	
18	Subtotal Expenses	263,030	15,779	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch G 2.3 L.23
20	Subtotal Revenue Requirement Ex. Return	263,030	15,779	
21	Return on Debt	-	-	Prorated on Rate Base - Sch G 2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch G 2.6 L.11
23	Total Revenue Requirement	263,030	15,779	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated

Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
Production																		
1	Diesel	101,424,536	46,346,579	55,077,957	-	-	-	-	-	-	-	-	-	-	-	-	-	
2	Subtotal Production	101,424,536	46,346,579	55,077,957	-	-	-	-	-	-	-	-	-	-	-	-	-	
Transmission																		
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution																		
6	Substation Structures & Equipment	3,834,105	2,361,427	-	-	1,472,678	-	-	-	-	-	-	-	-	-	-	-	
7	Land & Land Improvements	102,348	-	-	-	-	77,165	9,831	-	-	8,950	6,402	-	-	-	-	-	
8	Poles	13,745,724	-	-	-	-	7,949,812	2,716,870	-	-	1,407,122	1,671,920	-	-	-	-	-	
9	Primary Conductor & Equipment	2,449,563	-	-	-	-	2,172,763	276,801	-	-	-	-	-	-	-	-	-	
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Transformers	3,613,059	-	-	-	-	-	-	1,304,314	2,308,744	-	-	-	-	-	-	-	
12	Secondary Conductors & Equipment	369,948	-	-	-	-	-	-	-	-	215,680	154,268	-	-	-	-	-	
13	Services	857,470	-	-	-	-	-	-	-	-	-	-	857,470	-	-	-	-	
14	Meters	1,020,023	-	-	-	-	-	-	-	-	-	-	-	1,020,023	-	-	-	
15	Street Lighting	403,680	-	-	-	-	-	-	-	-	-	-	-	-	403,680	-	-	
16	Subtotal Distribution	26,395,920	2,361,427	-	-	1,472,678	10,199,740	3,003,501	1,304,314	2,308,744	1,631,753	1,832,590	857,470	1,020,023	403,680	-	-	
17	Subttl Prod, Trans, & Dist	127,820,456	48,708,006	55,077,957	-	1,472,678	10,199,740	3,003,501	1,304,314	2,308,744	1,631,753	1,832,590	857,470	1,020,023	403,680	-	-	
18	General	16,188,197	6,554,928	7,658,499	-	68,920	477,339	140,561	61,041	108,047	76,365	85,764	40,129	64,777	18,892	832,935	-	
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Software - General	555,378	211,636	239,313	-	6,399	44,318	13,050	5,667	10,031	7,090	7,963	3,726	4,432	1,754	-	-	
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
23	Total Plant	144,564,032	55,474,569	62,975,769	-	1,547,997	10,721,397	3,157,113	1,371,022	2,426,823	1,715,207	1,926,317	901,324	1,089,232	424,326	832,935	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch G 4.1 L.7
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch G 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch G 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Net Book Value

1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
Production																	
1	Diesel	76,035,619	34,744,954	41,290,665	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	76,035,619	34,744,954	41,290,665	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	1,723,562	728,201	-	-	995,362	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	24,670	-	-	-	-	18,600	2,370	-	-	2,157	1,543	-	-	-	-	-
8	Poles	4,989,483	-	-	-	-	2,885,658	986,181	-	-	510,763	606,881	-	-	-	-	-
9	Primary Conductor & Equipment	851,171	-	-	-	-	754,989	96,182	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,981,705	-	-	-	-	-	-	715,396	1,266,310	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	115,342	-	-	-	-	-	-	-	-	67,244	48,098	-	-	-	-	-
13	Services	395,847	-	-	-	-	-	-	-	-	-	-	395,847	-	-	-	-
14	Meters	720,172	-	-	-	-	-	-	-	-	-	-	-	720,172	-	-	-
15	Street Lighting	291,251	-	-	-	-	-	-	-	-	-	-	-	-	291,251	-	-
16	Subtotal Distribution	11,093,204	728,201	-	-	995,362	3,659,247	1,084,733	715,396	1,266,310	580,165	656,521	395,847	720,172	291,251	-	-
17	Subttl Prod, Trans, & Dist	87,128,823	35,473,155	41,290,665	-	995,362	3,659,247	1,084,733	715,396	1,266,310	580,165	656,521	395,847	720,172	291,251	-	-
18	General	7,778,683	3,149,746	3,680,029	-	33,117	229,369	67,542	29,331	51,918	36,694	41,211	19,283	31,126	9,078	400,239	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	606,243	246,822	287,301	-	6,926	25,461	7,548	4,978	8,811	4,037	4,568	2,754	5,011	2,027	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Net Book Value	95,513,749	38,869,723	45,257,995	-	1,035,405	3,914,077	1,159,823	749,704	1,327,039	620,896	702,300	417,884	756,310	302,355	400,239	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting		
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)		
	Production																
1	Diesel	7,944,573	3,630,322	4,314,250	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	230,067	105,131	124,937	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	8,174,640	3,735,453	4,439,187	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	688,366	64,058	-	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	-	10,951	-	-
9	Meters	37,547	-	-	-	-	-	-	-	-	-	-	-	37,547	-	-	-
10	Subtotal Distribution	725,913	64,058	-	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	37,547	10,951	-	-
11	Subttl Prod, Trans, & Dist	8,900,553	3,799,511	4,439,187	-	39,949	276,686	81,475	35,382	62,629	44,264	49,712	23,260	37,547	10,951	-	-
12	Customer Accounting	482,804	-	-	-	-	-	-	-	-	-	-	-	-	-	482,804	-
	Administrative & General:																
	Plant-Related:																
13	Production	678,462	310,027	368,434	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	352,550	31,540	-	-	19,669	136,230	40,115	17,421	30,836	21,794	24,476	11,453	13,624	5,392	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn and General Plt	472,077	181,153	205,649	-	5,055	35,011	10,310	4,477	7,925	5,601	6,290	2,943	3,557	1,386	2,720	-
18	Property Insurance	122,558	55,769	63,310	-	1,556	482	142	62	109	77	87	40	65	19	841	-
	Revenue Related:																
19	Municipal Tax	263,893	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	15,830	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	3,909,532	1,583,048	1,849,566	-	16,645	115,280	33,946	14,742	26,094	18,442	20,712	9,691	15,644	4,562	201,158	-
22	Prod, Trans, and Distn Expense-Related	71,283	30,430	35,553	-	320	2,216	653	283	502	355	398	186	301	88	-	-
23	Subtotal Admin & General	5,886,184	2,191,967	2,522,513	-	43,245	289,218	85,166	36,984	65,466	46,269	51,964	24,314	33,191	11,447	204,719	-
24	Total Operating & Maintenance Expenses	15,269,542	5,991,478	6,961,699	-	83,194	565,904	166,641	72,366	128,094	90,533	101,676	47,574	70,738	22,397	687,523	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Operating & Maintenance Expense (CONTD.)

Line No.	1 Description	18 Revenue Related		19 PUB Assessment	20 Basis of Functional Classification
		Municipal Tax			
	Production				
1	Diesel	-	-		Production - Demand, Energy ratios Sch G 4.1 L7
2	Other	-	-		Production - Demand, Energy ratios Sch G 4.1 L7
3	Subtotal Production	-	-		
	Transmission				
4	Transmission Lines	-	-		Prorated on Transmission Lines Plant in Service - Sch G 2.2 L.3
5	Terminal Stations	-	-		Prorated on Transmission Terminal Stations Plant in Service - Sch G 2.2 L.4
6	Other	-	-		Prorated on Transmission Plant in Service - Sch G 2.2 L.5
7	Subtotal Transmission	-	-		
	Distribution				
8	Other	-	-		Prorated on Distribution Plant, excluding Meters - Sch G 2.2 L. 16, less L. 14
9	Meters	-	-		Meters - Customer
10	Subtotal Distribution	-	-		
11	Subttl Prod, Trans, & Dist	-	-		
12	Customer Accounting	-	-		Accounting - Customer
	Administrative & General:				
	Plant-Related:				
13	Production	-	-		Prorated on Production Plant in Service - Sch G 2.2 L.2
14	Transmission	-	-		Prorated on Transmission Plant in Service - Sch G 2.2 L.5
15	Distribution	-	-		Prorated on Distribution Plant in Service - Sch G 2.2 L.16
16	Prod, Trans, Distn Plant	-	-		Prorated on Production, Transmission & Distribution Plant in Service - Sch G 2.2 L.17
17	Prod, Trans, Distn and General Plt	-	-		Prorated on Production, Transmission, Distribution & General Plant in Service - Sch G 2.2 L.23
18	Property Insurance	-	-		Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch G 2.2 L.2, 4, 6, 18 - 19
	Revenue Related:				
19	Municipal Tax	263,893	-		Revenue-related
20	PUB Assessment	-	15,830		Revenue-related
21	All Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-		Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	263,893	15,830		
24	Total Operating & Maintenance Expenses	263,893	15,830		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Production																	
1	Diesel	3,945,929	1,803,117	2,142,812	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	3,945,929	1,803,117	2,142,812	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substn Struct & Eqpt	73,312	39,828	-	-	33,484	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	696	-	-	-	-	524	67	-	-	61	44	-	-	-	-	-
8	Poles	305,675	-	-	-	-	176,786	60,417	-	-	31,291	37,180	-	-	-	-	-
9	Primary Conductor & Equipment	44,658	-	-	-	-	39,611	5,046	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	97,876	-	-	-	-	-	-	35,333	62,543	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	5,597	-	-	-	-	-	-	-	-	3,263	2,334	-	-	-	-	-
13	Services	17,274	-	-	-	-	-	-	-	-	-	-	17,274	-	-	-	-
14	Meters	53,951	-	-	-	-	-	-	-	-	-	-	-	53,951	-	-	-
15	Street Lighting	26,970	-	-	-	-	-	-	-	-	-	-	-	-	26,970	-	-
16	Subtotal Distribution	626,009	39,828	-	-	33,484	216,922	65,530	35,333	62,543	34,615	39,557	17,274	53,951	26,970	-	-
17	Subtotal Prod Tran & Dist	4,571,938	1,842,945	2,142,812	-	33,484	216,922	65,530	35,333	62,543	34,615	39,557	17,274	53,951	26,970	-	-
18	General	717,239	290,424	339,320	-	3,054	21,149	6,228	2,704	4,787	3,383	3,800	1,778	2,870	837	36,904	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	17,405	7,016	8,158	-	127	826	249	135	238	132	151	66	205	103	-	-
21	Software - General	159,900	64,456	74,943	-	1,171	7,587	2,292	1,236	2,187	1,211	1,383	604	1,887	943	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	5,466,481	2,204,841	2,565,232	-	37,836	246,484	74,299	39,408	69,755	39,341	44,891	19,722	58,914	28,853	36,904	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting			
						Demand (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)			
1	Average Net Book Value	95,513,749	38,869,723	45,257,995	-	1,035,405	3,914,077	1,159,823	749,704	1,327,039	620,896	702,300	417,884	756,310	302,355	400,239	-	
2	Cash Working Capital	62,057	25,254	29,405	-	673	2,543	754	487	862	403	456	272	491	196	260	-	
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Fuel Inventory - Diesel	5,700,591	-	5,700,591	-	-	-	-	-	-	-	-	-	-	-	-	-	
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Inventory/Supplies	1,653,208	634,397	720,179	-	17,703	122,608	36,104	15,679	27,753	19,615	22,029	10,307	12,456	4,853	9,525	-	
	Deterred Charges:																	
	Foreign Exchange Loss and Regulatory																	
7	Costs	4,590,894	1,868,284	2,175,338	-	49,767	188,131	55,747	36,035	63,784	29,844	33,756	20,086	36,352	14,533	19,238	-	
8	Retired Asset Pool	12,632,077	5,140,677	5,985,551	-	136,936	517,652	153,391	99,151	175,506	82,116	92,882	55,267	100,025	39,988	52,933	-	
9	Total Rate Base	120,152,576	46,538,335	59,869,059	-	1,240,484	4,745,011	1,405,819	901,056	1,594,945	752,874	851,424	503,815	905,634	361,925	482,195	-	
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Rate Base Available for Equity Return	120,152,576	46,538,335	59,869,059	-	1,240,484	4,745,011	1,405,819	901,056	1,594,945	752,874	851,424	503,815	905,634	361,925	482,195	-	
12	Return on Debt	3,616,593	1,400,804	1,802,059	-	37,339	142,825	42,315	27,122	48,008	22,662	25,628	15,165	27,260	10,894	14,514	-	
13	Return on Equity	2,246,853	870,267	1,119,551	-	23,197	88,732	26,289	16,850	29,825	14,079	15,922	9,421	16,935	6,768	9,017	-	
14	Return on Rate Base	5,863,446	2,271,071	2,921,610	-	60,536	231,557	68,604	43,972	77,833	36,740	41,549	24,586	44,195	17,662	23,531	-	

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch G 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch G 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and Regulatory	
7	Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch G 1.1,p2,L.16
13	Return on Equity	L.11 x Sch G 1.1,p2,L.19
14	Return on Rate Base	

[illegible]

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)	
	Amounts			
1	1.2 Domestic Diesel	3,281,626	3,281,626	
2	1.2G Government Domestic Diesel	826,883	826,883	
3	1.23 Churches, Schools & Com Halls	210,070	210,070	
4	2.1 GS 0-10 kW	1,307,106	1,307,106	
5	2.2 GS 10-100 kW	3,170,396	3,170,396	
6	2.3 GS 110-1,000 kVa	262,528	262,528	
7	2.4 GS Over 1,000 kVa	205,566	205,566	
8	4.1 Street and Area Lighting	110,871	110,871	
9	4.1G Gov't Street and Area Lighting	8,864	8,864	
10	Total	9,383,911	9,383,911	
	Ratios			
11	1.2 Domestic Diesel	0.3497	0.3497	
12	1.2G Government Domestic Diesel	0.0881	0.0881	
13	1.23 Churches, Schools & Com Halls	0.0224	0.0224	
14	2.1 GS 0-10 kW	0.1393	0.1393	
15	2.2 GS 10-100 kW	0.3379	0.3379	
16	2.3 GS 110-1,000 kVa	0.0280	0.0280	
17	2.4 GS Over 1,000 kVa	0.0219	0.0219	
20	4.1 Street and Area Lighting	0.0118	0.0118	
21	4.1G Gov't Street and Area Lighting	0.0009	0.0009	
22	Total	1.0000	1.0000	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service

1		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Customer (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
Allocated Revenue Requirement Excluding Return																	
1	1.2 Domestic Diesel	21,713,165	5,227,588	14,614,673	-	77,203	478,414	164,218	71,309	147,957	75,801	99,783	40,439	77,950	-	540,328	-
2	1.2G Government Domestic Diesel	773,651	189,095	506,352	-	2,793	17,305	4,328	2,579	3,899	2,742	2,630	1,066	2,054	-	14,240	-
3	1.23 Churches, Schools & Com Halls	1,169,126	207,725	903,736	-	3,068	19,010	3,604	2,834	3,248	3,012	2,190	888	1,711	-	11,860	-
4	2.1 GS 0-10 kW	3,206,931	626,901	2,253,390	-	9,258	57,372	28,456	8,551	25,639	9,090	17,291	13,156	25,360	-	93,630	-
5	2.2 GS 10-100 kW	8,327,862	1,655,279	6,273,105	-	24,446	151,486	8,960	22,579	8,072	24,002	5,444	10,524	20,287	-	29,480	-
6	2.3 GS 110-1,000 kVa	1,629,157	131,342	1,467,121	-	1,940	12,020	441	1,792	398	1,904	268	915	1,764	-	1,452	-
7	2.4 GS Over 1,000 kVa	1,222,889	99,671	1,102,839	-	1,472	9,122	74	1,360	66	1,445	45	153	294	-	242	-
8	4.1 Street and Area Lighting	259,262	39,123	107,940	-	578	3,580	9,048	534	8,152	567	5,498	-	-	51,177	29,771	-
9	4.1G Gov't Street and Area Lighting	263	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	38,302,306	8,176,723	27,229,155	-	120,758	748,311	219,129	111,538	197,431	118,564	133,148	67,140	129,420	51,177	721,003	-
Allocated Return on Debt and Equity																	
11	1.2 Domestic Diesel	3,458,350	1,451,954	1,568,112	-	38,702	148,040	51,413	28,112	58,329	23,489	31,138	14,808	26,619	-	17,634	-
12	1.2G Government Domestic Diesel	120,742	52,521	54,330	-	1,400	5,355	1,355	1,017	1,537	850	821	390	702	-	465	-
13	1.23 Churches, Schools & Com Halls	168,523	57,695	96,968	-	1,538	5,883	1,128	1,117	1,280	933	683	325	584	-	387	-
14	2.1 GS 0-10 kW	485,431	174,121	241,782	-	4,641	17,753	8,909	3,371	10,108	2,817	5,396	4,818	8,660	-	3,056	-
15	2.2 GS 10-100 kW	1,227,737	459,751	673,086	-	12,255	46,876	2,805	8,902	3,182	7,438	1,699	3,854	6,928	-	962	-
16	2.3 GS 110-1,000 kVa	201,250	36,480	157,418	-	972	3,719	138	706	157	590	84	335	602	-	47	-
17	2.4 GS Over 1,000 kVa	150,786	27,683	118,331	-	738	2,823	23	536	26	448	14	56	100	-	8	-
20	4.1 Street and Area Lighting	50,627	10,866	11,582	-	290	1,108	2,833	210	3,214	176	1,716	-	-	17,662	972	-
21	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total	5,863,446	2,271,071	2,921,610	-	60,536	231,557	68,604	43,972	77,833	36,740	41,549	24,586	44,195	17,662	23,531	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	91,984	5,518	
2	1.2G Government Domestic Diesel	23,177	1,390	
3	1.23 Churches, Schools & Com Halls	5,888	353	
4	2.1 GS 0-10 kW	36,638	2,198	
5	2.2 GS 10-100 kW	88,866	5,331	
6	2.3 GS 110-1,000 kVa	7,359	441	
7	2.4 GS Over 1,000 kVa	5,762	346	
8	4.1 Street and Area Lighting	3,108	186	
9	4.1G Gov't Street and Area Lighting	248	15	
10	Total	263,030	15,779	
	Allocated Return on Debt and Equity			
11	1.2 Domestic Diesel	-	-	
12	1.2G Government Domestic Diesel	-	-	
13	1.23 Churches, Schools & Com Halls	-	-	
14	2.1 GS 0-10 kW	-	-	
15	2.2 GS 10-100 kW	-	-	
16	2.3 GS 110-1,000 kVa	-	-	
17	2.4 GS Over 1,000 kVa	-	-	
20	4.1 Street and Area Lighting	-	-	
21	4.1G Gov't Street and Area Lighting	-	-	
22	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution											Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
							Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Demand (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	Customer (\$)	
	Total Revenue Requirement																
1	1.2 Domestic Diesel	25,171,515	6,679,542	16,182,786	-	115,905	626,454	215,631	99,421	206,286	99,290	130,921	55,247	104,569	-	557,962	-
2	1.2G Government Domestic Diesel	894,393	241,616	560,683	-	4,193	22,660	5,683	3,596	5,436	3,592	3,450	1,456	2,756	-	14,705	-
3	1.23 Churches, Schools & Com Halls	1,337,649	265,420	1,000,704	-	4,606	24,893	4,733	3,951	4,528	3,945	2,874	1,213	2,295	-	12,247	-
4	2.1 GS 0-10 kW	3,692,362	801,021	2,495,172	-	13,900	75,125	37,365	11,923	35,746	11,907	22,686	17,974	34,020	-	96,686	-
5	2.2 GS 10-100 kW	9,555,598	2,115,030	6,946,191	-	36,701	198,362	11,765	31,481	11,255	31,440	7,143	14,378	27,215	-	30,442	-
6	2.3 GS 110-1,000 kVa	1,830,407	167,822	1,624,539	-	2,912	15,739	580	2,498	554	2,495	352	1,250	2,366	-	1,500	-
7	2.4 GS Over 1,000 kVa	1,373,675	127,354	1,221,170	-	2,210	11,944	97	1,896	92	1,893	59	208	394	-	250	-
8	4.1 Street and Area Lighting	309,889	49,989	119,522	-	867	4,688	11,881	744	11,366	743	7,213	-	-	68,839	30,742	-
9	4.1G Gov't Street and Area Lighting	263	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total	44,165,752	10,447,794	30,150,766	-	181,293	979,867	287,733	155,509	275,264	155,305	174,698	91,727	173,615	68,839	744,534	-
Re-classification of Revenue-Related																	
11	1.2 Domestic Diesel	0	25,974	62,927	-	451	2,436	838	387	802	386	509	215	407	-	2,170	-
12	1.2G Government Domestic Diesel	(0)	6,824	15,836	-	118	640	161	102	154	101	97	41	78	-	415	-
13	1.23 Churches, Schools & Com Halls	0	1,244	4,691	-	22	117	22	19	21	18	13	6	11	-	57	-
14	2.1 GS 0-10 kW	(0)	8,515	26,523	-	148	799	397	127	380	127	241	191	362	-	1,028	-
15	2.2 GS 10-100 kW	0	21,057	69,155	-	365	1,975	117	313	112	313	71	143	271	-	303	-
16	2.3 GS 110-1,000 kVa	0	718	6,952	-	12	67	2	11	2	11	2	5	10	-	6	-
17	2.4 GS Over 1,000 kVa	(0)	569	5,454	-	10	53	0	8	0	8	0	1	2	-	1	-
20	4.1 Street and Area Lighting	(0)	537	1,284	-	9	50	128	8	122	8	78	-	-	740	330	-
21	4.1G Gov't Street and Area Lighting	(263)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total	(263)	65,438	192,824	-	1,135	6,137	1,666	974	1,594	973	1,012	602	1,140	740	4,311	-
Total Allocated Revenue Requirement																	
23	1.2 Domestic Diesel	25,171,515	6,705,516	16,245,713	-	116,356	628,890	216,469	99,808	207,088	99,676	131,430	55,462	104,975	-	560,132	-
24	1.2G Government Domestic Diesel	894,393	248,440	576,519	-	4,311	23,300	5,843	3,698	5,590	3,693	3,548	1,497	2,834	-	15,120	-
25	1.23 Churches, Schools & Com Halls	1,337,649	266,664	1,005,395	-	4,627	25,010	4,755	3,969	4,549	3,964	2,887	1,218	2,306	-	12,304	-
26	2.1 GS 0-10 kW	3,692,362	809,536	2,521,695	-	14,047	75,924	37,763	12,049	36,126	12,034	22,928	18,165	34,382	-	97,714	-
27	2.2 GS 10-100 kW	9,555,598	2,136,087	7,015,346	-	37,066	200,337	11,882	31,794	11,367	31,753	7,214	14,522	27,486	-	30,745	-
28	2.3 GS 110-1,000 kVa	1,830,407	168,540	1,631,491	-	2,925	15,807	582	2,509	557	2,505	353	1,256	2,376	-	1,506	-
29	2.4 GS Over 1,000 kVa	1,373,675	127,923	1,226,624	-	2,220	11,998	97	1,904	93	1,902	59	209	396	-	251	-
32	4.1 Street and Area Lighting	309,889	50,527	120,806	-	877	4,739	12,008	752	11,488	751	7,291	-	-	69,579	31,072	-
33	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total	44,165,488	10,513,232	30,343,589	-	182,429	986,005	289,399	156,483	276,858	156,277	175,709	92,329	174,755	69,579	748,845	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Total Revenue Requirement			
1	1.2 Domestic Diesel	91,984	5,518	
2	1.2G Government Domestic Diesel	23,177	1,390	
3	1.23 Churches, Schools & Com Halls	5,888	353	
4	2.1 GS 0-10 kW	36,638	2,198	
5	2.2 GS 10-100 kW	88,866	5,331	
6	2.3 GS 110-1,000 kVa	7,359	441	
7	2.4 GS Over 1,000 kVa	5,762	346	
8	4.1 Street and Area Lighting	3,108	186	
9	4.1G Gov't Street and Area Lighting	248	15	
10	Total	263,030	15,779	
	Re-classification of Revenue-Related			
11	1.2 Domestic Diesel	(91,984)	(5,518)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
12	1.2G Government Domestic Diesel	(23,177)	(1,390)	
13	1.23 Churches, Schools & Com Halls	(5,888)	(353)	
14	2.1 GS 0-10 kW	(36,638)	(2,198)	
15	2.2 GS 10-100 kW	(88,866)	(5,331)	
16	2.3 GS 110-1,000 kVa	(7,359)	(441)	
17	2.4 GS Over 1,000 kVa	(5,762)	(346)	
20	4.1 Street and Area Lighting	(3,108)	(186)	
21	4.1G Gov't Street and Area Lighting	(248)	(15)	
22	Total	(263,030)	(15,779)	
	Total Allocated Revenue Requirement			
23	1.2 Domestic Diesel	-	-	
24	1.2G Government Domestic Diesel	-	-	
25	1.23 Churches, Schools & Com Halls	-	-	
26	2.1 GS 0-10 kW	-	-	
27	2.2 GS 10-100 kW	-	-	
28	2.3 GS 110-1,000 kVa	-	-	
29	2.4 GS Over 1,000 kVa	-	-	
32	4.1 Street and Area Lighting	-	-	
33	4.1G Gov't Street and Area Lighting	-	-	
34	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Expenses																
1	Operating & Maintenance	2,238,392	1,275,200	-	-	100,796	307,043	89,651	25,448	45,045	51,710	56,720	9,086	28,797	13,580	142,113	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	756,000	-	756,000	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	4,104,300	-	4,104,300	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,420,232	955,999	-	-	35,204	185,452	56,845	19,694	34,861	31,631	35,597	4,086	30,524	19,412	10,926	-
	Expense Credits																
8	Sundry	(7,321)	(4,171)	-	-	(330)	(1,004)	(293)	(83)	(147)	(169)	(186)	(30)	(94)	(44)	(465)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Pole Attachments	(61,423)	-	-	-	-	(35,524)	(12,140)	-	-	(6,288)	(7,471)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(432)	-	-	-	-	-	-	-	-	-	-	-	-	-	(432)	-
16	Meter Test Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Expense Credits	(69,176)	(4,171)	-	-	(330)	(36,528)	(12,434)	(83)	(147)	(6,457)	(7,656)	(30)	(94)	(44)	(897)	-
18	Subtotal Expenses	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal Revenue Requirement Ex. Return	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
21	Return on Debt	807,239	515,833	2,820	-	80,989	93,023	26,427	11,363	20,114	15,514	16,789	2,004	12,497	7,038	2,828	-
22	Return on Equity	501,507	320,468	1,752	-	50,316	57,792	16,418	7,059	12,496	9,639	10,430	1,245	7,764	4,372	1,757	-
23	Total Revenue Requirement	9,758,496	3,063,329	4,864,871	-	266,976	606,783	176,908	63,482	112,368	102,037	111,880	16,391	79,488	44,358	156,727	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Functional Classification	20
		Municipal Tax (\$)	PUB Assessment (\$)		
	Expenses				
1	Operating & Maintenance	87,928	5,275	Carryforward from Sch G 2.4 L.24	
2	Fuels	-	-	Production - Energy	
3	Fuels-Diesel	-	-	Production - Energy	
4	Fuels-Gas Turbine	-	-	Production - Energy	
5	Power Purchases -CF(L)Co	-	-		
6	Power Purchases-Other	-	-	Carryforward from Sch G 4.4 L.21	
7	Depreciation	-	-	Carryforward from Sch G 2.5 L.23	
	Expense Credits				
8	Sundry	(288)	(17)	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24	
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch G 2.2 L.17	
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24	
11	Suppliers' Discounts	-	-	Prorated on Total Operating & Maintenance Expenses - Sch G 2.4 L.24	
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch G 4.1 L.37	
13	Secondary Energy Revenues	-	-	Production - Energy	
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch G 4.1 L.16	
15	Application Fees	-	-	Accounting - Customer	
16	Meter Test Revenues	-	-	Meters - Customer	
17	Total Expense Credits	(288)	(17)		
18	Subtotal Expenses	87,641	5,257		
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch G 2.3 L.23	
20	Subtotal Revenue Requirement Ex. Return	87,641	5,257		
21	Return on Debt	-	-	Prorated on Rate Base - Sch G 2.6 L.9	
22	Return on Equity	-	-	Prorated on Rate Base - Sch G 2.6 L.11	
23	Total Revenue Requirement	87,641	5,257		

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup

Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Substations Demand (\$)	Primary Lines Demand (\$)	Customer (\$)	Line Transformers Demand (\$)	Customer (\$)	Secondary Lines Demand (\$)	Customer (\$)	Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)	Accounting Customer (\$)	Specifically Assigned Customer (\$)
Production																	
1	Diesel	20,618,739	20,618,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	20,618,739	20,618,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission																	
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution																	
6	Substation Structures & Equipment	2,430,420	66,299	-	-	2,364,122	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	452,466	-	-	-	-	341,137	43,459	-	-	39,568	28,302	-	-	-	-	-
8	Poles	9,870,601	-	-	-	-	5,708,642	1,950,944	-	-	1,010,434	1,200,581	-	-	-	-	-
9	Primary Conductor & Equipment	1,561,625	-	-	-	-	1,385,161	176,464	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,706,981	-	-	-	-	-	-	616,220	1,090,761	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	346,715	-	-	-	-	-	-	-	-	202,135	144,580	-	-	-	-	-
13	Services	220,006	-	-	-	-	-	-	-	-	-	-	220,006	-	-	-	-
14	Meters	517,483	-	-	-	-	-	-	-	-	-	-	-	517,483	-	-	-
15	Street Lighting	328,828	-	-	-	-	-	-	-	-	-	-	-	-	328,828	-	-
16	Subtotal Distribution	17,435,125	66,299	-	-	2,364,122	7,434,941	2,170,867	616,220	1,090,761	1,252,136	1,373,463	220,006	517,483	328,828	-	-
17	Subttl Prod, Trans, & Dist	38,053,864	20,685,037	-	-	2,364,122	7,434,941	2,170,867	616,220	1,090,761	1,252,136	1,373,463	220,006	517,483	328,828	-	-
18	General	3,153,661	1,876,333	-	-	142,013	446,618	130,404	37,016	65,522	75,216	82,504	13,216	42,644	19,753	222,420	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	165,343	89,876	-	-	10,272	32,305	9,432	2,677	4,739	5,441	5,968	956	2,248	1,429	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Plant	41,372,868	22,651,247	-	-	2,516,407	7,913,864	2,310,704	655,914	1,161,022	1,332,793	1,461,935	234,178	562,376	350,009	222,420	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch G 4.1 L.8
2	Subtotal Production	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	Subtotal Transmission	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch G 4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch G 4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch G 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	Subtotal Distribution	
17	Subttl Prod, Trans, & Dist	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch G 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	Total Plant	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Production																
1	Diesel	15,033,294	15,033,294	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	15,033,294	15,033,294	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	2,440,494	9,074	-	-	2,431,420	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	334,240	-	-	-	-	252,000	32,104	-	-	29,229	20,907	-	-	-	-	-
8	Poles	3,308,260	-	-	-	-	1,913,326	653,884	-	-	338,660	402,390	-	-	-	-	-
9	Primary Conductor & Equipment	524,157	-	-	-	-	464,927	59,230	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	917,847	-	-	-	-	-	-	331,343	586,505	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	120,694	-	-	-	-	-	-	-	-	70,365	50,329	-	-	-	-	-
13	Services	54,609	-	-	-	-	-	-	-	-	-	-	54,609	-	-	-	-
14	Meters	365,361	-	-	-	-	-	-	-	-	-	-	-	365,361	-	-	-
15	Street Lighting	207,035	-	-	-	-	-	-	-	-	-	-	-	-	207,035	-	-
16	Subtotal Distribution	8,272,698	9,074	-	-	2,431,420	2,630,253	745,218	331,343	586,505	438,254	473,626	54,609	365,361	207,035	-	-
17	Subttl Prod, Trans, & Dist	23,305,992	15,042,368	-	-	2,431,420	2,630,253	745,218	331,343	586,505	438,254	473,626	54,609	365,361	207,035	-	-
18	General	1,218,691	725,085	-	-	54,879	172,590	50,393	14,305	25,320	29,066	31,883	5,107	16,479	7,633	85,951	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	162,163	104,665	-	-	16,918	18,301	5,185	2,305	4,081	3,049	3,295	380	2,542	1,441	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Net Book Value	24,686,846	15,872,117	-	-	2,503,217	2,821,144	800,796	347,953	615,906	470,370	508,805	60,096	384,383	216,109	85,951	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Production																
1	Diesel	822,932	822,932	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	13,430	13,430	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Subtotal Production	836,362	836,362	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	453,948	1,779	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	-	8,823	-	-
9	Meters	19,049	-	-	-	-	-	-	-	-	-	-	-	19,049	-	-	-
10	Subtotal Distribution	472,997	1,779	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	19,049	8,823	-	-
11	Subttl Prod, Trans, & Dist	1,309,359	838,141	-	-	63,436	199,500	58,250	16,535	29,268	33,598	36,854	5,903	19,049	8,823	-	-
12	Customer Accounting	99,353	-	-	-	-	-	-	-	-	-	-	-	-	-	99,353	-
	Administrative & General:																
	Plant-Related:																
13	Production	40,074	40,074	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	45,672	174	-	-	6,193	19,476	5,687	1,614	2,857	3,280	3,598	576	1,356	861	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn & General Plt	3,364	1,842	-	-	205	643	188	53	94	108	119	19	46	28	18	-
18	Property Insurance	35,075	30,201	-	-	3,355	598	175	50	88	101	110	18	57	26	298	-
	Revenue Related:																
19	Municipal Tax	87,928	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	5,275	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related Prod, Trans, and Distn Expense-	601,806	358,056	-	-	27,100	85,227	24,885	7,064	12,503	14,353	15,744	2,522	8,138	3,769	42,444	-
22	Related	10,486	6,713	-	-	508	1,598	467	132	234	269	295	47	153	71	-	-
23	Subtotal Admin & General	829,680	437,059	-	-	37,360	107,542	31,400	8,913	15,777	18,111	19,866	3,182	9,749	4,756	42,760	-
24	Total Operating & Maintenance Expenses	2,238,392	1,275,200	-	-	100,796	307,043	89,651	25,448	45,045	51,710	56,720	9,086	28,797	13,580	142,113	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	Description	18	19	20
		Revenue Related		
		Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch G 4.1 L8
2	Other	-	-	Production - Demand, Energy ratios Sch G 4.1 L8
3	Subtotal Production	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch G 2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch G 2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.5
7	Subtotal Transmission	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch G 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	Subtotal Distribution	-	-	
11	Subttl Prod, Trans, & Dist	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch G 2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch G 2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch G 2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch G 2.2 L.17
17	Prod,Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch G 2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch G 2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	87,928	-	Revenue-related
20	PUB Assessment	-	5,275	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
	Prod, Trans, and Distn Expense- Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	Subtotal Admin & General	87,928	5,275	
24	Total Operating & Maintenance Expenses	87,928	5,275	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmission Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lighting Customer (\$)		
	Production																
1	Diesel	831,373	831,373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Subtotal Production	831,373	831,373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	27,473	296	-	-	27,177	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	7,258	-	-	-	-	5,472	697	-	-	635	454	-	-	-	-	-
8	Poles	229,935	-	-	-	-	132,982	45,447	-	-	23,538	27,967	-	-	-	-	-
9	Primary Conductor & Equipment	21,388	-	-	-	-	18,971	2,417	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	47,675	-	-	-	-	-	-	17,211	30,464	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	4,672	-	-	-	-	-	-	-	-	2,724	1,948	-	-	-	-	-
13	Services	3,309	-	-	-	-	-	-	-	-	-	-	3,309	-	-	-	-
14	Meters	27,371	-	-	-	-	-	-	-	-	-	-	-	27,371	-	-	-
15	Street Lighting	17,756	-	-	-	-	-	-	-	-	-	-	-	-	17,756	-	-
16	Subtotal Distribution	386,836	296	-	-	27,177	157,426	48,561	17,211	30,464	26,897	30,370	3,309	27,371	17,756	-	-
17	Subtotal Prod Tran & Dist	1,218,208	831,669	-	-	27,177	157,426	48,561	17,211	30,464	26,897	30,370	3,309	27,371	17,756	-	-
18	General	154,920	92,173	-	-	6,976	21,940	6,406	1,818	3,219	3,695	4,053	649	2,095	970	10,926	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	GEC and AFUDC	4,499	3,071	-	-	100	581	179	64	112	99	112	12	101	66	-	-
21	Software - General	42,606	29,087	-	-	950	5,506	1,698	602	1,065	941	1,062	116	957	621	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Depreciation Expense	1,420,232	955,999	-	-	35,204	185,452	56,845	19,694	34,861	31,631	35,597	4,086	30,524	19,412	10,926	-

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount (\$)	3 Production Demand (\$)	4 Production Energy (\$)	5 Transmission Demand (\$)	Distribution											16 Accounting Customer (\$)	17 Specifically Assigned Customer (\$)
						6 Substations Demand (\$)	7 Primary Lines Demand (\$)		8 Customer (\$)	9 Line Transformers Demand (\$)		10 Customer (\$)	11 Secondary Lines Demand (\$)		12 Customer (\$)	13 Services Customer (\$)	14 Meters Customer (\$)	15 Street Lightin Customer (\$)
1	Average Net Book Value	24,686,846	15,872,117	-	-	2,503,217	2,821,144	800,796	347,953	615,906	470,370	508,805	60,096	384,383	216,109	85,951	-	-
2	Cash Working Capital	16,039	10,312	-	-	1,626	1,833	520	226	400	306	331	39	250	140	56	-	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	93,674	-	93,674	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	473,133	259,036	-	-	28,777	90,502	26,425	7,501	13,277	15,242	16,718	2,678	6,431	4,003	2,544	-	-
	Deterred Charges:																	
	Foreign Exchange Loss and																	
7	Regulatory Costs	1,186,580	762,898	-	-	120,318	135,599	38,490	16,724	29,604	22,608	24,456	2,889	18,475	10,387	4,131	-	-
8	Retired Asset Pool	362,309	232,942	-	-	36,738	41,404	11,753	5,107	9,039	6,903	7,467	882	5,641	3,172	1,261	-	-
9	Total Rate Base	26,818,581	17,137,305	93,674	-	2,690,676	3,090,481	877,984	377,511	668,226	515,429	557,777	66,584	415,180	233,811	93,944	-	-
10	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rate Base Available for Equity Return	26,818,581	17,137,305	93,674	-	2,690,676	3,090,481	877,984	377,511	668,226	515,429	557,777	66,584	415,180	233,811	93,944	-	-
12	Return on Debt	807,239	515,833	2,820	-	80,989	93,023	26,427	11,363	20,114	15,514	16,789	2,004	12,497	7,038	2,828	-	-
13	Return on Equity	501,507	320,468	1,752	-	50,316	57,792	16,418	7,059	12,496	9,639	10,430	1,245	7,764	4,372	1,757	-	-
14	Return on Rate Base	1,308,747	836,300	4,571	-	131,305	150,815	42,846	18,423	32,609	25,153	27,220	3,249	20,261	11,410	4,584	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch G 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Energy
4	Fuel Inventory - Diesel	
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch G 2.2, L. 23
	Deterred Charges:	
	Foreign Exchange Loss and	
7	Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Retired Asset Pool	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Portion	
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch G 1.1,p2,L.16
13	Return on Equity	L.11 x Sch G 1.1,p2,L.19
14	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Basis of Allocation to Classes of Service

[illegible]

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.1 Domestic Diesel	609,244	609,244
2	1.12 Domestic All Electric	1,321,780	1,321,780
3	2.1 GS 0-10 kW	899,489	899,489
4	2.2 GS 10-100 kW	-	-
5	2.3 GS 110-1,000 kVa	277,254	277,254
6	4.1 Street and Area Lighting	18,925	18,925
7	Total	3,126,692	3,126,692
	Ratios		
8	1.1 Domestic Diesel	0.1949	0.1949
9	1.12 Domestic All Electric	0.4227	0.4227
10	2.1 GS 0-10 kW	0.2877	0.2877
11	2.2 GS 10-100 kW	-	-
12	2.3 GS 110-1,000 kVa	0.0887	0.0887
13	4.1 Street and Area Lighting	0.0061	0.0061
14	Total	1.0000	1.0000

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmsn Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Allocated Revenue Requirement Excluding Return																
1	1.1 Domestic Diesel	1,889,747	554,506	959,029	-	33,781	113,531	48,946	11,219	29,120	19,143	30,910	2,890	13,024	-	55,547	-
2	1.12 Domestic All Electric	3,816,627	1,057,198	2,172,394	-	64,405	216,453	56,699	21,390	33,733	36,498	35,806	3,348	15,087	-	64,346	-
3	2.1 GS 0-10 kW	2,046,179	489,511	1,259,419	-	29,821	100,224	23,141	9,904	13,768	16,900	14,614	6,518	29,373	-	26,262	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	626,992	119,082	456,772	-	7,255	24,381	778	2,409	463	4,111	491	387	1,743	-	883	-
6	4.1 Street and Area Lighting	70,204	6,731	12,687	-	410	1,378	4,498	136	2,676	232	2,841	-	-	32,948	5,105	-
7	Total	8,449,749	2,227,028	4,860,300	-	135,671	455,967	134,062	45,059	79,759	76,884	84,661	13,142	59,227	32,948	152,142	-
	Allocated Return on Debt and Equity																
8	1.1 Domestic Diesel	334,557	208,230	902	-	32,694	37,551	15,643	4,587	11,906	6,263	9,938	715	4,455	-	1,674	-
9	1.12 Domestic All Electric	605,009	397,002	2,043	-	62,332	71,594	18,121	8,745	13,792	11,940	11,512	828	5,161	-	1,939	-
10	2.1 GS 0-10 kW	286,771	183,823	1,185	-	28,861	33,150	7,396	4,049	5,629	5,529	4,699	1,611	10,048	-	791	-
11	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2.3 GS 110-1,000 kVa	63,877	44,718	430	-	7,021	8,064	249	985	189	1,345	158	96	596	-	27	-
13	4.1 Street and Area Lighting	18,533	2,528	12	-	397	456	1,438	56	1,094	76	913	-	-	11,410	154	-
14	Total	1,308,747	836,300	4,571	-	131,305	150,815	42,846	18,423	32,609	25,153	27,220	3,249	20,261	11,410	4,584	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Allocated Revenue Requirement Excluding Return			
1	1.1 Domestic Diesel	17,077	1,024	
2	1.12 Domestic All Electric	37,049	2,223	
3	2.1 GS 0-10 kW	25,213	1,512	
4	2.2 GS 10-100 kW	-	-	
5	2.3 GS 110-1,000 kVa	7,771	466	
6	4.1 Street and Area Lighting	530	32	
7	Total	87,641	5,257	
	Allocated Return on Debt and Equity			
8	1.1 Domestic Diesel	-	-	
9	1.12 Domestic All Electric	-	-	
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	-	-	
13	4.1 Street and Area Lighting	-	-	
14	Total	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Line No.	Description	Total Amount (\$)	Production Demand (\$)	Production Energy (\$)	Transmsn Demand (\$)	Distribution										Accounting Customer (\$)	Specifically Assigned Customer (\$)
						Substations Demand (\$)	Primary Lines Demand (\$)		Line Transformers Demand (\$)		Secondary Lines Demand (\$)		Services Customer (\$)	Meters Customer (\$)	Street Lightin Customer (\$)		
	Total Revenue Requirement																
1	1.1 Domestic Diesel	2,224,304	762,736	959,931	-	66,474	151,082	64,589	15,806	41,025	25,406	40,847	3,604	17,480	-	57,221	-
2	1.12 Domestic All Electric	4,421,637	1,454,200	2,174,437	-	126,737	288,047	74,820	30,136	47,524	48,438	47,318	4,175	20,248	-	66,285	-
3	2.1 GS 0-10 kW	2,332,950	673,333	1,260,604	-	58,682	133,374	30,537	13,954	19,397	22,428	19,312	8,129	39,421	-	27,054	-
4	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	2.3 GS 110-1,000 kVa	690,869	163,801	457,201	-	14,276	32,446	1,026	3,394	652	5,456	649	482	2,339	-	909	-
6	4.1 Street and Area Lighting	88,737	9,259	12,699	-	807	1,834	5,936	192	3,770	308	3,754	-	-	44,358	5,258	-
7	Total	9,758,496	3,063,329	4,864,871	-	266,976	606,783	176,908	63,482	112,368	102,037	111,880	16,391	79,488	44,358	156,727	-
	Re-classification of Revenue-Related																
8	1.1 Domestic Diesel	-	6,258	7,876	-	545	1,240	530	130	337	208	335	30	143	-	469	-
9	1.12 Domestic All Electric	0	13,032	19,486	-	1,136	2,581	670	270	426	434	424	37	181	-	594	-
10	2.1 GS 0-10 kW	(0)	7,803	14,608	-	680	1,546	354	162	225	260	224	94	457	-	314	-
11	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	2.3 GS 110-1,000 kVa	0	1,977	5,517	-	172	392	12	41	8	66	8	6	28	-	11	-
13	4.1 Street and Area Lighting	0	59	81	-	5	12	38	1	24	2	24	-	-	283	34	-
14	Total	0	29,128	47,568	-	2,539	5,770	1,605	604	1,019	970	1,015	167	810	283	1,421	-
	Total Allocated Revenue Requirement																
15	1.1 Domestic Diesel	2,224,304	768,994	967,807	-	67,020	152,322	65,119	15,936	41,362	25,615	41,182	3,634	17,623	-	57,690	-
16	1.12 Domestic All Electric	4,421,637	1,467,231	2,193,923	-	127,872	290,629	75,490	30,406	47,950	48,872	47,742	4,213	20,430	-	66,879	-
17	2.1 GS 0-10 kW	2,332,950	681,136	1,275,212	-	59,363	134,919	30,891	14,115	19,621	22,688	19,536	8,223	39,878	-	27,367	-
18	2.2 GS 10-100 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2.3 GS 110-1,000 kVa	690,869	165,777	462,718	-	14,448	32,837	1,039	3,435	660	5,522	657	488	2,367	-	920	-
20	4.1 Street and Area Lighting	88,737	9,318	12,780	-	812	1,846	5,973	193	3,794	310	3,778	-	-	44,641	5,292	-
21	Total	9,758,496	3,092,457	4,912,440	-	269,514	612,552	178,512	64,086	113,387	103,008	112,895	16,558	80,298	44,641	158,148	-

NEWFOUNDLAND & LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related		19 Basis of Proration
		Municipal Tax (\$)	PUB Assessment (\$)	
	Total Revenue Requirement			
1	1.1 Domestic Diesel	17,077	1,024	
2	1.12 Domestic All Electric	37,049	2,223	
3	2.1 GS 0-10 kW	25,213	1,512	
4	2.2 GS 10-100 kW	-	-	
5	2.3 GS 110-1,000 kVa	7,771	466	
6	4.1 Street and Area Lighting	530	32	
7	Total	87,641	5,257	
	Re-classification of Revenue-Related			
8	1.1 Domestic Diesel	(17,077)	(1,024)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
9	1.12 Domestic All Electric	(37,049)	(2,223)	
10	2.1 GS 0-10 kW	(25,213)	(1,512)	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	(7,771)	(466)	
13	4.1 Street and Area Lighting	(530)	(32)	
14	Total	(87,641)	(5,257)	
	Total Allocated Revenue Requirement			
15	1.1 Domestic Diesel	-	-	
16	1.12 Domestic All Electric	-	-	
17	2.1 GS 0-10 kW	-	-	
18	2.2 GS 10-100 kW	-	-	
19	2.3 GS 110-1,000 kVa	-	-	
20	4.1 Street and Area Lighting	-	-	
21	Total	-	-	

Functionalization & Classification Ratios

[illegible]

[illegible]

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	Island Isolated	Labrador Isolated	L'Anse au Loup	Labrador Interconnected
1	Sales+Losses for System Load Factor (MWh)	7,416,874	6,022	46,089	27,047	2,810,079
2	Hours in Year	8,760	8,760	8,760	8,760	8,760
3	Average Demand (kW)	846,675	687	5,261	3,088	320,785
4	Coincident Peak at Generation (kW)	1,683,676	1,809	9,688	6,105	480,169
1	System Load Factors	50.29%	38.00%	54.30%	50.57%	66.81%

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Holyrood Capacity Factor

	1	2	3	4	5
Line No.	Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1	2020 Actual	988,816,044	466	8,760	24.22%
2	2021 Actual	710,554,100	466	8,760	17.43%
3	2022 Actual	744,880,000	466	8,760	18.27%
4	2023 Actual	648,605,350	466	8,760	15.91%
5	2024 Actual	666,289,026	466	8,760	16.34%
6	5-Year Average	751,828,904	466	8,760	18.43%
7	Current Year	455,225,658	466	8,760	11.16%

NEWFOUNDLAND AND LABRADOR HYDRO
2027 Test Year Cost of Service Study (No Rate Mitigation)
Total System
Power Purchases

Line No.	1	2	3	4	5	6	7	8	
		Total (\$)	Production Demand (\$)	Production & Transmission Energy (\$)	Transmission Export Demand (\$)	Transmission Network Demand (\$)	Rural Transmission Demand (\$)	Distribution Demand (\$)	Basis of Functional Classification
Island Interconnected:									
1	DLP Secondary	0		0					Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-					Production - Energy (Secondary)
3	Wheeling	960,000					960,000		Rural Transmission
4	Interruptible Demand	7,891,076	7,891,076						Production - Demand
5	Interruptible Energy	-		-					Production - Energy
6	Non-utility Generation excluding wind	36,232,222	18,012,022	18,220,200					Energy: System Load Factor
7	Wind Purchases	15,683,047	6,743,710	8,939,337					Production - Energy
8	Muskrat Falls Generation	269,134,556	133,794,098	135,340,458					Energy: System Load Factor
9	Total Exports	(40,178,593)	(19,973,870)	(20,204,723)					Energy: System Load Factor
10	Power Purchases - LTA Costs	46,146,683	22,940,770	23,205,914	-				Energy: System Load Factor
11	Power Purchases - LIL Costs	465,082,406	231,205,096	233,877,310	-				Energy: System Load Factor
12	Tariff Revenue	(18,337,593)	(9,116,116)	(9,221,477)	-				Energy: System Load Factor
13	Recapture to the Island	-	-	-	-				Energy: System Load Factor
14	Rate Mitigation	-	-	-	-				
15	Subtotal	782,613,805	391,496,786	390,157,018	-	-	960,000	-	
Labrador Interconnected:									
16	CF(L)Co	1,554,061	515,843	1,038,217					Energy: System Load Factor
17	Other	-	-						Labrador Lynx Interruptible
18									
19	Subtotal	1,554,061	515,843	1,038,217	-	-	-	-	
Isolated Systems:									
20	Mary's Harbour	309,793		309,793					Production - Energy
21	L'Anse au Loup	4,104,300		4,104,300					Production - Energy
22	Ramea Wind	177,100	76,153	100,947					Production - Energy
23	Subtotal	4,591,193	76,153	4,515,040	0	0	0	0	
24	Total	788,759,058	392,088,782	395,710,276	-	-	960,000	-	